ARMENIA POWER SECTOR 2006 LEAST COST GENERATION PLAN

PROGRAM TO STRENGTHEN REFORM AND ENHANCE ENERGY SECURITY IN ARMENIA

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Armenia Power Sector 2006 Least Cost Generation Plan

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EXECUTVE SUMMARY

The 2006 Least Cost Generation Plan (LCGP) is an updated version of the extensive efforts made to produce the previous Least Cost Generation Plans. This plan was prepared by the Ministry of Energy of the Republic of Armenia (RoA) with support from PA Consulting Group (USAID's "Program to Strengthen Reform and Enhance Energy Security in Armenia"). The 2006 LCGP focuses on continued investment in safety upgrade projects at the Armenian Nuclear Power Plant (ANPP) and its retirement, decommissioning, and replacement, consistent with "Energy Sector Development Strategies in Context of Economic Development in Armenia" which was adopted by the Government of Armenia (GoA) in June 2005.

The Least Cost Generation Plan was prepared by the Ministry of Energy (MoE) with support from PA in 2005. However, several important events took place in the recent past that affected many of the main assumptions used in the analysis, necessitating a revision and updating of the LCGP. At the end of 2005 Russia's *Gasprom* increased the price for natural gas for most of the former Soviet Republics including Armenia. This increase was expected to take place gradually over 20 years. Instead, natural gas prices doubled on April 1, 2006, and this important factor had to be taken into consideration when assessing the results of the study. The second reason, supporting the decision to upgrade the LCGP 2005, was the early publication of the Energy Information Administration's (EIA) "Annual Energy Outlook 2006" with updated long-term projections for world crude oil prices, including crude oil price developments for late 2005 to early 2006. An assessment of other forecasts, assumptions, and scenarios revealed minor or no changes to the results, hence the Demand Forecast and Generation Options remain the same as the LCGP 2005.

The purpose of the 2006 LCGP report is to assist the GoA and international and donor organizations in determining viable solutions for a sustainable and an economically feasible program for securing a long-term electric power supply for the consumers of Armenia. Of particular concern are issues surrounding the ANPP such as safety, the timing of its retirement, generation replacement and rate impacts, nuclear plant decommissioning methodologies, the collection of decommissioning funds, and the creation and management of a decommissioning fund.

The 2006 LCGP process applied scenario analysis to develop recommendations based on expected future demands, fuel cost, operating, capital costs, and maintenance expenditures. The best alternatives were tested against potential future economic and market conditions (i.e. demand, fuel price, and capital cost forecasts) and the potential timing for retirement of the ANPP to determine validity of the long-term recommendations under differing conditions. This updated LCGP provides key findings from the analysis performed in 2006 and a two-year action plan for the power sector of Armenia that is aligned with the long-term least cost generation plan.

Study Period

The study period for the 2006 LCGP is 2006-2025.

Energy Sector Status

Armenia's energy sector reforms and accomplishments are exemplary: Armenia's electric distribution network was privatized in 2002; it is one of the few countries in the developing world that has achieved a combination of 24x365 electric supply available to paying

customers; 100% collection from the customers; and 100% payment to generators and service providers.

The energy sector of Armenia has gone through significant change, including restructuring and privatization. The contributing factors were improved legal and regulatory improvements, laying the ground work for commercial operations including, but not limited to: the power market structure, transparent wholesale trading rules, cost recovery tariffs, and service rules. Although the regulatory improvements have been substantial, significant assistance is required to ensure sustainability.

Another significant development in the power sector was the privatization of the Electrical Networks of Armenia (ENA – Distribution Company), purchased by Midland Resources Holding, and its subsequent sale to a RAO UES' subsidiary, and the sale of Hrazdan unit No.5 to a subsidiary of Russia's Gasprom's.

The Iran-Armenia transmission interconnection capability was increased when new 220 kV power lines were commissioned. There is a plan to increase the transfer capability with Iran through construction of a new transmission line. Also, negotiations with Georgia are underway that may result in construction of a new 400 kV line. The completion of these projects would provide Armenia with a wider opportunity for parallel operations and power exchange.

Extensive capital investment by various entities in the energy sector demonstrates the change in commercial conditions and positive future prospects for investment in Armenia. Armenia's energy sector accomplishments should make it easier for investors and developers to obtain financing for their proposed projects. Furthermore, Armenia is the only country in the region with 25 years of nuclear generation experience and has over 1,300 MW of power exchange capability with neighboring countries. Given the regional demand for electricity, Armenia has the potential to become a major exporter to the region (Iran, Georgia, Turkey, and Azerbaijan).

Electricity Demand Forecast

The actual electricity demand in 2005 was within the forecasted range that was used in LCGP 2005. Therefore, the LCGP 2005 demand forecast was used for the LCGP 2006 study as well.

The peak and energy demand for domestic consumption in Armenia has increased since 2002. The latest forecast of peak and energy has a higher starting point and a higher growth rate than the previous LCGP. The annual growth for peak and energy is forecasted to be about 2.6% per year starting from initial values of 5,529 GWh (energy) and 1,293 MW (peak load) in 2005. The focus of this planning exercise is to develop a plan for meeting Armenia's domestic electric power needs over the study period at the lowest possible cost while taking into account other factors such as those established in the "Energy Sector Development Strategies in Context of Economic Development in Armenia."

Demand-Side Management

The energy loads are not reduced by explicit demand-side management options, even though there are plenty of options to select from. Demand-side management is less attractive because investments to rehabilitate the networks continue, the country has an extreme surplus of generation capacity, tariffs are low, and energy efficiency programs are not able to attract sufficient capital.

The load forecast is however somewhat dampened by the assumption that expansion of the gas system will displace a measure of electricity for heating applications, self-generation of electricity will develop through micro and small hydro plants, and self-producing of synthetic gas from biomass will replace electrical heating at some of agricultural enterprises.

Existing Generation Capacity

The Armenian power sector has roughly 100% excess capacity. The major plants are the Armenian Nuclear Power Plant (ANPP), Hrazdan and Yerevan Thermal Power Plants (TPPs), and the hydropower plants on Vorotan and Sevan-Hrazdan Cascades. However, these plants are old and require extensive upgrading or replacement.

The plants have not performed the capital improvements recommended in the past, and their O&M budgets have been consistently under-funded for many years. This situation cannot continue indefinably and it puts the continued operation and reliability of the plants at risk.

Of particular concern is the ANPP where safety issues continue to be attract attention. Funding ANPP's safety upgrades, various investments, and the eventual decommissioning needs to be addressed by the Government of Armenia (GoA). The investment issues need to be addressed as soon as possible to protect the public from potential accidents, to secure the funds needed to properly decommission the plant, and to provide for the continued safe and reliable operation of the plant. The 2005 LCGP considers investment requirements for continuing operation of ANPP through 2015, taking into account improvements needed to address IAEA safety issues, potential life extension beyond 2016, plant decommissioning, and capacity replacement and additions.

Generation Capacity Requirements

In the 2005 LCGP, a reserve capacity margin of 30% is assumed; therefore, the annual peak load is multiplied by 1.3 to determine annual capacity requirements. The reserve capacity of 30% assumes that the Armenian system is independent of the systems in neighboring countries. Many future scenarios are examined in this 2005 LCGP. The "reference case" or "reference scenario" assumes that ANPP will be retired in the fourth quarter of 2015, and the average peak and energy demands will grow at 2.7% and 3.1% per year respectively. The forecasted generating capacity requirements (excluding reserve) for the reference case are 1,293 MW in 2005 increasing to 2,198 MW in 2025.

Future Supply Options

Since coal, wind and solar were not found to be viable generation options to meet base load requirements for Armenia, only gas fired, hydro, and nuclear generation options were analyzed in the LCGP process. The natural gas-fired options include completing Hrazdan as a combined cycle unit, creating a new combined cycle unit, or developing new small gas turbines. The new hydro generation options included Shnokh (70 MW), Megri (140 MW), and Lori-Berd (68 MW). Also, the new nuclear generation options considered were AP-1000 (USA), CANDU 6 (Canada), ACR-1000 (Canada), VVER-1000 (Russia), and EPR (France/Germany). ANPP's life extension through 2036 was also considered as a nuclear option.

Fuels

Natural gas and nuclear fuel prices were reviewed and forecasted through 2025 for this LCGP.

Nuclear fuel is assumed to increase at 3% per year for the next 20 years.

Natural gas prices are impacted by world crude oil prices that have significantly increased since 2003. Regional market conditions and Russian natural gas prices at its Western border also add to uncertainties in fuel prices. The price of natural gas is the key driver in the forecast of electric power costs for Armenia.

The recent developments related to fuel price have significantly affected certain LCGP assumptions. Firstly, the gas price increase for Armenia by Russia's *Gasprom* (doubling the price effective April 1st of 2006), and secondly, Energy Information Administration's early release of the Annual Energy Outlook 2006 with updated long-term projections for world crude oil prices, capturing crude oil price developments for late 2005 to early 2006. These two events were taken into consideration in the new fuel forecast, resulting in higher price expectations for Armenia.

While the Iran-Armenia gas pipeline may provide some level of competition for the gas supply to Armenia, it is unlikely that the price of gas from Iran would be significantly lower than the price of gas from Russia.

Financial Factors

General inflation was assumed to rise at 4.5% per annum over the study period. For sensitivity analysis, three main scenarios regarding weighted average cost of capital were analyzed in the LCGP 2006: 8.48%, 12.7% and 14.9%. The construction of a 225 MW CCGT at the Yerevan TPP site was modeled to be financed by JBIC at 0.75% interest rate.

Key Findings

The key findings in this LCGP are:

- There is no economic alternative to continued operation of the ANPP through 2015. However, its continued operation shall be predicated by assurances that the plant will be fully funded for regular maintenance and safety upgrades;

- Armenia would need roughly 2,000 MW of new capacity by 2020, if ANPP is retired in 2016 and the existing ageing thermal capacity (all Hrazdan and Yerevan units would be over 45 years old in 2020) is retired;

- ANPP life extension past 2016 is not feasible because of investment cost and additional spent fuel disposal cost;

- No Armenian hydropower plant (existing or new) is capable of operating as a base load capacity due to limited capacity of their water reservoir. The least cost generation option for the Armenian power sector, when base load capacity is needed, is nuclear or combined cycle gas turbine generation;

- Higher gas prices make the replacement of existing thermal units even more attractive and critical than before due to their age and inefficiency;

- The planned Meghri hydro-power plant (140 MW Armenia's share) will not be available to serve Armenia's load during this planning horizon;

- Hrazdan unit No. 5 was sold to Russia's *Gasprom* and if available for Armenia's domestic needs, may cover a portion of the demand and potentially eliminate the need for construction of a new 400 MW CCGT;

- The largest system risk is the insecure single gas supply line that the construction of the Iran - Armenia pipeline may rectify;
- Diversity of generation mix should be maintained for economic and electric system security; and,
- New nuclear generation is the least cost option, provides for diversity of fuel mix, and from the fuel supply standpoint is most reliable. In the meantime, a higher level of capital investment for nuclear generation requires a special approach for the selection of funding mechanisms. However, in the long-term (until 2025) the nuclear option becomes economically more profitable, as compared to the thermal option, from the point of view of total cost assessment.

Recommendations

Based on the analysis performed and strategic and economic consideration, the following recommendations are provided:

1. Decommission the ANPP in 2016 or earlier, when the new nuclear unit is ready;
2. Fully fund the safety improvements and investment requirements of ANPP for its safe operation through 2015;
3. Conduct a comprehensive safety and environmental assessment of the ANPP site to determine the site's viability for decommissioning and construction of new nuclear generation;
4. Develop a comprehensive decommissioning plan to be implemented five years prior to the commencement of ANPP's decommissioning;
5. Determine the funding sources for decommissioning ANPP, establish a credible decommissioning fund, select a fund manager to manage the fund while investing in low risk investment monitored by international organizations;
6. Develop and implement a plan to address concerns regarding Armenia's ability to finance and construct a new nuclear unit, including unit size and disposal issues;
7. Develop and implement a plan to address concerns regarding Armenia's ability to replace existing thermal units at Hrazdan and Yerevan TPPs with new units;
8. Develop indigenous renewable resources in order to increase energy independence and diversity;
9. Develop and implement a plan that rewards Energy Efficiency, making it economically attractive for consumers to invest in new equipment and applications;
10. Establish and implement a plan for minimizing the rate impact on consumers of ANPP decommissioning, and the commissioning of new generation capacity; and,
11. Develop and implement a plan to address vulnerable consumers' needs for assistance, given the utility investment requirements.

Two-Year Action Plan

There are several decisions to be made and action plans completed over the next two years in order to address the following issues:

- ANPP's decommissioning date has to be determined, formalized through passage of law in the National Assembly, and communicated to the Armenian public and international organizations;
- A comprehensive safety and environmental assessment of the exiting ANPP site must be performed to determine the feasibility of the site for various decommissioning options and for a potential new nuclear unit;
- A decommissioning study should be completed, decommissioning and waste disposal plans and standards should be developed, a decommissioning fund created, and collection of decommissioning costs from consumers included in retail rates;
- The costs related to safety improvements should be collected through retail rates and/or provided through grants by international organizations to ensure the continued safe operation of the ANPP;
- Fully fund and complete necessary capital improvements for safety improvements of ANPP as well as those required to continue operation through 2015;
- Perform detailed technical and economic analysis and explore the financing approach and options for constructing new generation capacity prior to 2016;
- Develop a plan to address the following concerns in order to make new nuclear generation a viable option:

    (a) Given the high level of capital investment required for the construction of new nuclear generation in Armenia, a funding "special approach" should be developed with corresponding legislation that allows for attracting private capital investment;

    (b) The sizing of the unit should take into account the existing system and development of a large unit option as part of a potential regional power market; and,

    (c) Selection of a proper waste disposal option.

- Priorities should be developed for capital improvement programs to ensure that utility consumers of Armenia can afford to pay for the most urgent improvements, not just in the electric sector, but in all public service sectors (water, natural gas, telecommunications, and electric transportation);
- The Public Services Regulatory Commission (PSRC) should develop a plan for minimizing the rate impact on consumers for ANPP decommissioning, and commissioning new generation capacity; and,
- Given Armenia's projected need for large-scale investment in the energy sector, a significant number of consumers (pensioners, low income families, etc.) would need assistance to pay for their utility services. The GoA should develop a plan, with donors' assistance, to put in place a social safety net/utility assistance program for low-income families/ pensioners.

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1. INTRODUCTION AND BACKGROUND

1.1 ENERGY SECTOR STATUS

In early to mid 90's Armenia experience severe hardship, when the electric generation supply was limited and few hydro units were operational. The lessons learned from that era and the winter of 2002-2003, when the gas supply from Russia was interrupted for an extended period, provided Armenia with a better perspective and understanding of how to plan for the future energy needs.

Armenia's energy sector reforms and accomplishments are exemplary: Armenia's electric distribution network was privatized in 2002; it is one of the few countries in the developing world that has achieved a combination of 24x365 electric supply available to paying customers; 100% collection from the customers; and 100% payment to generators and service providers.

The energy sector of Armenia has gone through a significant change, including restructuring and privatization. The contributing factors were legal and regulatory improvements, which laid the ground work for commercial operations including, but not limited to: power market structure, transparent wholesale trading rules, cost recovery tariffs, and service rules. Although the regulatory improvements have been substantial, significant assistance is required to ensure sustainability.

The second most significant developments in the power sector was the privatization of the Electrical Networks of Armenia (ENA – distribution company), which was purchased by Midland Resources Holding, and subsequent sale to a RAO UES' subsidiary, and the sale of Hrazdan unit No.5 to a Russian Gasprom's subsidiary.

The Iran-Armenia transmission interconnection capability was increased when the new 220 kV power lines were commissioned. Plans are to increase the transfer capability with Iran through construction of a new transmission line. Also, negotiations with Georgia are underway, which may result in construction of a new 400 kV line. The completion of these projects would provide Armenia with a greater opportunity for parallel operations and power exchange.

An extensive capital investment by various entities in the energy sector demonstrates the change in commercial conditions and good future prospects for investment in Armenia. Armenia's accomplishments may make it easier for the investors and developers to obtain financing for their projects. Furthermore, Armenia is the only country in the region with 25 years of nuclear generation experience and has over 1300 MW of power exchange capability with the neighboring countries. Given the regional demand for electricity, Armenia has the potential to become a major exporter to the region (Iran, Georgia, Turkey, and Azerbaijan).

1.2 NEED FOR A POWER SUPPLY PLAN

The Government of Armenia (GoA) ratified a plan, "Energy Sector Development Strategies within the Context of Economic Development in Armenia", in June 2005 to provide direction for development of the Armenian energy sector. The energy strategy provided the boundaries and direction for the development of a long term supply plan for the electric sector in Armenia.

A comprehensive evaluation of the future of the Armenian power sector is important for the security of the country, power system, and for developing a programmatic approach to

a sustainable, reliable, efficient and cost-effective power sector for the Armenian electric consumers. The 2006 Least Cost Generation Plan (LCGP) provides a supply plan for the future of the power sector and an action plan for the next two years for the initiation of its implementation, consistent with the GoA approved energy strategy.

The analysis performed for the development of the LCGP provides the basis for making appropriate decisions related to the future of the power sector.

Several key decisions need to be made by the GoA, Public Services Regulatory Commission (PSRC), and the Armenian Nuclear Regulatory Commission (ANRA) in the very near future including:

- Should the ANPP be retired on, before, or after 2016?
- What are the rate impacts on retail electric consumers for early retirement of the ANPP and how will the PSRC manage those rate impacts, both from the affordability perspective and impact on economic development?
- What legal and regulatory mandates and standards will govern ANPPs decommissioning and related waste disposal in Armenia?
- What is the best option for decommissioning the ANPP and what are the sources of funds to pay for the decommissioning?
- How the decommissioning fund should be managed to ensure appropriate safeguards are in place and appropriate resources are available when needed?
- What signals the consumers need in order to switch from electricity to gas for their needs, when it is more efficient and economical to do so?
- What areas of energy security impart to the largest risks and what strategic actions can/should the GoA take to reduce those risks?
- How can the continued operation of the old thermal plants be secured, and when they should be retired?
- What is the appropriate generation mix that would provide for national security at an optimum cost?
- What should be the structure of ownership and the source of funding for the new generation capacity?

The LCGP process provides for a comprehensive analysis and results that can provide guidance to GoA, PSRC, ANRA, and power market entities on above issues.

The specific objectives of the 2006 LCGP is to:

- Review previous least cost plan reports and analysis and recommendations;
- Assess the current electricity-supply-demand balance of Armenia and forecast future developments/possible scenarios for the power sector;
- Conduct operational, economic, and strategic evaluation of possible actions to reduce costs, mitigate risks;
- Develop an updated plan through 2025, based on best available information and objective assessment with recommendations for resources to meet long-term needs of the power sector;
- Provide an annual investment program indicating the capital requirements for the rehabilitation and expansion of the country's generation facilities;

- Establish a near-term action plan that supports the long-term least cost generation plan.
- Provide GoA and the international donor community with a complete and sound analysis of the power development options for the Armenian electricity sector, based on internationally accepted principles;
- Assist GoA and donor agencies in determining viable solutions for a sustainable and an economically viable program for securing a long-term electric power supply to the consumers of Armenia; taking into account concerns related to the ANPP (safety, retirement, viable replacements and rate impacts, nuclear plant decommissioning methodologies, the collections of decommissioning funds, and the creation and management of a decommissioning fund).

1.3 ENERGY POLICY OF ARMENIA

"*The Energy Sector Development Strategies within the Context of Economic Development in Armenia*" which was adopted on June 23, 2005 Session provides insights to GoA's focus and strategy for implementing its energy policy.

The Energy Policy of Armenia is based on the principles adopted by the international community for the sustainable development of the society and, in particular, the energy sector. It is guided by the tendencies of economic development and by the experience accumulated in the energy sector of the Republic.

The energy policy goals are:

- Achieving sustainable economic development in Armenia;
- Ensuring safety in the energy sector;
- Enhancing the energy independence of the country, including diversification of imported and domestic energy resources and ensuring maximum utilization of generating capacity;
- Ensuring efficient use of domestic energy resources and alternative sources of energy and implementation of economic and legal mechanisms for that purpose.

In order to achieve these goals, Strategies are developed to:

- Provide reliable energy supply at low rates to satisfy the fundamental needs of all customers, while enhancing energy conservation;
- Avoid reliance on import of energy sources that might expose the security and economy of Armenia to political events beyond the control of the Republic of Armenia;
- Ensure the safe operation of the ANPP through 2016 or such time as its energy can be replaced and decommissioning can proceed without unacceptable economic, ecological and energy security impacts;
- Ensure ecologically sustainable energy supply, based on the principles of sustainable development and in compliance with the international environmental commitments of the Republic of Armenia;
- Construct a financially sustainable energy system that encourages the economically efficient operation of all energy suppliers and that would bring forth interest among the investors and private capital;

- Create an electric energy system that is export oriented and generates high added value;
- Develop research programs that targets implementation of the goals and primary objectives specified in these Strategies, with the employment of the newest energy sector technologies known in the world, as well as the latest developments in the global energy system.

2. RECENT SUPPLY PLAN STUDIES

2.1 THE 2002 AND 2005 LEAST COST GENERATION PLANS

The 2002 Least Cost Plan (2002 LCP) prepared by PA Consulting, funded by USAID, utilized data sources and studies developed by various organizations and consultants [including, but not limited to: Lahmeyer 1996 The Least Cost Power Sector Investment Program, Hagler Bailly (currently PA) 1999 O&M Report, Hagler Bailly 2000 LCGP Report, Resolutions of the Regulatory Commission on Tariffs, and Data from power sector companies].

The information on existing hydropower plants was collected mostly from previous studies performed by European consultants, Hager Bailly, Harza Engineering, Burns and Roe Enterprises, hydro power institute, and hydropower plants (HPPs).

Previous studies provided data on the actual physical condition of existing plants and assessments of future plant sites. This included information on turbine wear, stream-flow projections, and sedimentation data for potential plant sites. Historical data on power plants' output, the system peaks and hourly loads and energy transfers on international connections (exports and imports) were obtained from the National Dispatch Center. Also, information on prospective generation projects was obtained from the 2000 LCP efforts, which were updated at the end of 2002.

The 2005 Least Cost Generation Plan (LCGP) was an update of the extensive efforts of the previous Least Cost Generation Plans. This plan was prepared by the Ministry of Energy of the Republic of Armenia (RoA) with support from PA Consulting Group (USAID's "Program to Strengthen Reform and Enhance Energy Security in Armenia"). The 2005 LCGP focused on continued investment in safety upgrade projects at the Armenian Nuclear Power Plant (ANPP) and its retirement, decommissioning, and replacement, consistent with "Energy Sector Development Strategies in Context of Economic Development in Armenia" which was adopted by the Government of Armenia (GoA) in June 2005.

An assessment of other forecasts, assumptions, and scenarios revealed minor or no changes to the results, hence the Demand Forecast and Generation Options remain the same as the LCGP 2005.

2.2 TACIS WORK IN 2003

On December 4, 2001 during the fifth meeting of the Joint European Commission (EC)-Armenia Working Group on ANPP, the Commission announced the possible financial assistance for the development of alternatives for the replacement of the ANPP. The Commission committed itself to organizing an international conference of other donors to support Armenia in developing a policy framework to facilitate the necessary investments, notably the involvement of private capital.

The Commission, through TACIS, contracted Carl Bro and MVV in 2003 to develop alternative options for the replacement of ANPP based on an independent expert assessment of the Armenia's near- and long-term electricity supply and demand. The goal was to provide the Commission with a final result of the prioritization of alternative options already carried out within the framework of the previous contract and to:

- Reinforce the credibility of the economic evaluation of investment projects;

- Provide the international donor community with a complete and sound analysis of the power development options of the Armenian electricity sector, based on the principle of least cost planning.

The assessment was completed in late 2003 and concluded that:

2) The future electricity demand will increase, but probably slowly;
3) The future electricity supply will be based upon natural gas, hydro and probably nuclear power;
4) A natural gas supply pipeline from Iran is not very likely;
5) The actual change of ownership and financial management of the existing power plants will be problematic;
6) There are no major technical problems to the shut down of ANNP; the lost generation capacity can be replaced either by the existing gas fired power generating units or by new gas fired units. However, a premature closure of the plant will have the following consequences:
   a) The variable cost will increase with around 45% if ANPP is replaced by a new NGCC and around 70% if the existing units are used to replace the lost generation capacity.
   b) The fixed cost will decrease around 20% with a new NGCC and 25% without a new unit
   c) The total cost (O&M, capital for rehabilitation of gas pipes, new plants and decommissioning) will increase by about 80% the first year after decommissioning or $80-90 Million/year for 2003-2015 period.
   d) The total cost increase will be about the same if ANPP is replaced by a new NGCC or if the existing units are used to replace the lost generation capacity.
   e) The dependency on one fuel from a single source (pipeline) will increase from 45% to 85%.
   f) CO2 emissions will increase by 80-120%
   g) Uncertainties concerning demand growth and utilization time will only have minor influence on the above (a-g) conclusions.

2.3 IAEA 2004 STUDY

The International Atomic Energy Agency (IAEA), under its technical cooperation program, conducted a joint study of Energy and Nuclear Power Planning (ENPP) of Armenia in 2004. The objective of the study was to analyze the electricity demand as part of the total final energy demand under various scenarios of Armenian socioeconomic and technological development, and to develop economically optimized electric generating system expansion plans for meeting the electric power demand, and to assess the role that nuclear energy could play within these optimal programs. The specific objectives of this study were to:

- Define the role that nuclear power could play in the future electricity supply in Armenia, based on a least-cost expansion planning analysis of the country's power system;
- Analyze the environmental impacts of such a nuclear power development;
- Evaluate the financial viability of the envisaged nuclear power development program;

- Train a group of Armenian energy specialist in the use of the IAEA's energy models.

Similar to other IAEA technical cooperation projects, the ENPP study was conceived as a joint effort of Armenia and the IAEA, where each side had its own clear, well-established responsibilities:

- Armenian experts had full responsibility for the conduct of the study, including data collection and preparation, execution of the computer runs, interpretation and improvement of results, etc., up to the production of the draft report of the study;
- The IAEA experts provided guidance and coordination throughout the conduct of the study, on-the-job training of the national team and transfer of know-how, and the necessary methodologies and computerized planning tools to Armenia.

A number of Expert Missions were arranged by the IAEA for providing technical assistance to the national team for the implementation of this study. In addition, the IAEA provided extensive training to the members of the national team on the use of various computer based planning models used for the analysis of various aspects of energy and electricity planning.

The detailed analyses carried out in this study show that the demand for energy and electricity could continue to increase during the years at about 7-9% per annum. Due to increased use of energy, the environmental emissions from the energy sector will also increase, threatening severe degradation of natural environment. The study has shown that in order to combat those problems, the following measures should be implemented:

- Rehabilitate all existing hydropower plants as soon as possible.
- Rehabilitate existing thermal power plants and CHP units.
- Implement aggressively demand-side management campaign and carry out cost effective measures without delay.
- Keep the operating nuclear power plant till its design life with enhanced nuclear safety, not only relevant to the plant, but also considering the system measures, such as strengthening of the HV transmission system, interconnection to neighboring countries, provision of adequate levels of spinning reserve, and load management to increase the low system load at night.
- Add Shnokh, Megri and Gekhi HPPs, as well as 75 MW of small hydro between 2012 and 2017, and implement 15 MW of wind farm and other renewable projects.
- Add gas fired CHP Combined Cycle Plants (668 MW) according to heat demand and electricity demand growth.
- Maintain Hydro-Potential Stocks of Lake Sevan by reducing Irrigation losses.

3. PREVIOUS RECOMMENDATIONS AND CURRENT CONSIDERATIONS

3.1 ANALYSIS PERFORMED IN THE 2002 LEAST COST PLAN

The LCP 2002 forecasted the growth of domestic power system peak demand to be less than 1% per year. The reserve margin was estimated at 25% of the annual peak demand. The resulting capacity requirement was forecasted to rise from 1360 MW in 2003 to 1568 MW in 2022.

The results of the 2002 LCGP showed that no additional capacity would be needed prior to the retirement of ANPP in 2008. The least cost resources included re-powering of Harazdan Unit #5 as a combined cycle generating unit by 2006, a new combined cycle plant, and simple cycle gas turbine units. The least cost option was the Unit #5 at the Hrazdan TPP and the next viable generation option selected was a new 400 MW combined cycle unit built on either the Hrazdan or Yerevan thermal power plant sites after 2006.

3.2 RECOMMENDATIONS OF THE 2002 LCGP

The key findings of the 2002 LCP were:

- There is no need for new generating capacity until the ANPP is retired;
- After the ANPP is retired, new generation resources are needed when the old facilities can no longer produce energy;
- Operating the ANPP until its expected retirement date is significantly more economical than any other option. Retiring the plant in late 2008 rather than late 2014 carries an economic penalty (capital, fuel, decommissioning, and other costs) of about $100 million per year, assuming minimal increase in cost of natural gas;
- Many of the old thermal generating units are not needed by the power sector, now or in the future. Two condensing units at the Yerevan TPP, three CHPs at the Yerevan TPP, and 4 CHPs at the Hrazdan TPP should be retired in the very near future.
- The least cost generation option for the Armenian power sector, when generation is needed, is a gas turbine/ combined cycle units.

The report also recommended a number of actions to be taken in 2003 and 2004. These actions included:

- Completing a decommissioning study of NAPP, developing decommissioning and waste disposal plans and standards, creating a decommissioning fund, and including the decommissioning costs in the retail rates;
- Collecting the costs related to safety improvements at ANPP through retail rates and compensating ANPP for these costs so that the plant can continue to operate safely;
- Retiring and properly dismantling non-essential units;
- Compensating all operating power plants for their operation and maintenance expenses;

- Ensuring continued operation of thermal and hydro plants that are not retired by compensating them for capital improvements and including those costs in retail rates;
- Developing priorities for all capital improvement programs to ensure that the residents of Armenia can afford to pay for the most urgent improvements, not just in the electric sector, but also in all public sectors (water, natural gas, telephone, and electric transportation); and
- Developing a plan for minimizing the rate shock at the time of the nuclear plant retirement date. The Energy Regulatory Commission (ERC) should develop this plan.

3.3 LESSONS LEARNED SINCE THE COMPLETION OF THE 2002 LCP (2002-2005)

3.3.1 Load Forecast

The 2002 LCP projected less than 1% per year demand (peak and energy) growth. Recent history shows that the average annual energy growth from 2002 to 2004 was about 0.7% while the peak load actually decreased by about 0.4%. Armenia's annual domestic peak demand has experienced very little change since 1998. It should be noted that Armenia experienced an abnormally cold winter in 2002, which affected the peak.

3.3.2 Lack of End-Use Information

As was noted in previous LCPs, lack of end-use data hampers the ability of system planners in examining the real drivers of electricity growth and determining the cost-effectiveness of demand-side management programs.

Since 2002 when the distribution networks in Armenia was privatized, system commercial losses have been reduced substantially. However, lack of precise information on customer base changes (such as number of customers broken down into existing and new, as well as individual statistics on their consumption) makes it impossible to assess whether the growth (or what percentage of the growth) in consumption was due to distribution company's administrative measures or due to improved economic situation. Such statistical data is fundamental for identification of the changes in consumption patterns for each customer class, or the impacts of energy efficiency and demand-side management programs on the overall system load, establishing trends in customer class consumptions, demand forecasts, and tariff setting.

3.3.3 Continued Operation of the Power Plants

The capacity margin in 2002 was approximately 100%, far too much excess capacity for the retail electric consumers to financially support. It was recommended that some of the older units must be retired since they are not providing any useful value to the retail electric consumers. The remaining thermal units needed to be thoroughly evaluated to determine their condition and the cost to maintain them into the future.

Since the need for energy from the non-nuclear, non-hydro generating units was small and infrequent, the thermal condensing units can still provide generating capacity at a low cost and therefore be economically beneficial for the system and electric consumers. In 2002, a major concern was the lack of payment to the generators for purchased power, which impacted regular maintenance and the occasional capital improvements that are necessary to keep these units available and operable during the occasional low reserve

margin periods. However, since the privatization of the Distribution Company (November 2002) and establishment of the direct contracts (for capacity and energy) between the generators and Distribution Company, all generators have been paid 100% of their PSRC approved tariff. Also, since 2002 the structure of power plants' ownership has changed: Hrazdan TPP was given to the Russian Government (debt for asset swap); Sevan Cascade hydro plants were given to RAO "UES" (fuel debt for asset swap); and Hrazdan TPP unit #5 was sold to Iran. Currently the GoA only owns ANPP and Yerevan TPP. Therefore, if a generator is not maintaining its unit, it would not be able to generate electricity, and it would not get paid. Hence there is an incentive to maintain the generating units. PSRC is also planning to introduce an availability testing procedure to prevent the generators from gaming the system; claiming that their unit(s) is available for operation, when the unit is not able to operate at dispatcher's request at the rated capacity.

The 2002 LCP provided an annual investment plan for 2002-2022. This investment plan included O&M, capital improvement costs for the old plants until they are retired, and capital for new plants as needed. However, the required capital improvements have not been completed and the units' dependable capacities have been affected. The existing units' design capacity, net dependable capacity, and in service date are shown in Table 3.1.

The current age of Armenia's generating units vary from 21 to 70 years old, and all existing gas fired units (Hrazdan and Yerevan) are over 31 years old**.** Also, no Armenian hydro power plant is capable of operating as a base load capacity due to limited capacity of their water reservoir or availability of water**.**

Table 3.1 Existing Generating Capacity

	Design Capacity	Gross Dependable Capacity at Peak Demand	Start Up Dates	Reasons for Difference
Hydro				**Water Limitation and/ or Equipment Deterioration**
Vorotan	***405***	***400***	***1970-1984***	
Sevan-Hrazdan	***561***	***445***	***1936-1961***	
Dzora	***25***	***5***	***1932***	
SHPPs	***31***	***4***	***1930s-present***	
Gas-Fired				**Equipment Deterioration**
Hrazdan	**1110**	**1030**	**1971-1974**	
Yerevan	**590**	**500**	**1963-1966**	
ANPP Unit#2	***440***	***380***	**1980 (1989-1995 removed from operation)**	**Equipment Limitation**
Total	**3162**	**2764**		

3.3.4 Benefits of Continued Operation of the ANPP

The 1996 general agreement between the EU and the GoA stated that the ANPP would retire in 2004 or if and when an economic replacement of the ANPP could be found, financing made available and replacement generation construction completed. The 2002 LCP did not identify any viable economic replacement for the ANPP before the expiration of its 30 year design life, estimated to be around 2016.

There are no plans to retire the ANPP before 2016. The latest TACIS analysis, late 2003, concluded that a premature retiring of ANPP (before the end of its design life in 2016) will increase the system costs by $80 to $90 million per year for the period from the time ANPP is retired to 2016. In addition, early retirement of ANPP will exasperate Armenia's dependency on a single source of natural gas, increasing her dependency from 45% to about 85%; furthermore, CO_2 emissions will double.

The IAEA 's 2004 study also concluded that among other things Armenia should continue operating ANPP through its design life, provided that plant safety is enhanced and the overall system operation is strengthen by improving reliability of the HV transmission system, interconnection to the neighboring countries, while providing for adequate spinning reserve and instituting demand side management measures that would increase low system nightly load.

While Armenia's excess capacity allows the ANPP to shut down at any time without causing power shortages, the economic, energy security, and environmental consequences for Armenia are substantial and contrary to the goals and objectives of GoA's energy strategy adopted in June 2005.

Plans, including investment and funding plans, should be developed and implemented to ensure safety and reliability upgrades are applied at ANPP, in addition to routine maintenance, and sufficient funds are available for its decommissioning in 2016.

3.3.5 Important Site Selection Issues for New Generation Resources

There are several site selection issues that need to be evaluated for new generation resources. Some evaluation studies have already begun, but the analysis should continue.

The primary site selection issues are:

- Transmission system access, availability, and reliability;
- Fuel supply (Natural gas, fuel oil, etc.) and transportation availability and reliability;
- Transportation (roads, railroads) infrastructure accessibility and conditions;
- Water resources availability; and,
- Air emissions and other environmental impacts

a. ELECTRIC TRANSMISSION CAPABILITY

Armenia has an extensive transmission network that had the capability to transport over 3000 MW of generation capacity and about 16,000 GWh of energy within Armenia and the neighboring countries. The transmission network is being rehabilitated as funding becomes available.

Currently the GoA is planning the construction of a second transmission circuit between the Shinuair substation and Ararat Substation in order to increase the amount of energy exchange with Iran. Also, the rehabilitation of the 220 kV substations, funded by World Bank, was completed in 2005 and the rehabilitation of 110 kV substations funded by JBIC should commence in 2006.

Armenia has significant transmission system interconnection capability with the neighboring countries.

- Armenia- Iran, two 220 kV transmission lines that were built in 1997 and 2003 with 300- 450 MW capacity. Plans are to increase the capacity to 600 MW. Armenia exported 446 GWh of electricity to Iran and imported 215 GWh from Iran in 2004.
- Armenia-Georgia, one 220 kV transmission line with 250 MW capacity, and two 110 kV transmission lines with a total capacity of 100 MW. Armenia exported 475 GWh of electricity to Georgia in 2004.
- Armenia-Azerbaijan, one 330 KV line with 420 MW capacity, which is currently disconnected.
- Armenia-Turkey, one 220 KV line with 300 MW capacity, which is currently disconnected.

b. NATURAL GAS TRANSPORTATION CAPABILITY AND LOCATION

Currently, Armenia receives 100% of its gas from Russia through a pipeline that goes through the troubled regions in Russia and then through Georgia. The pipeline has been sabotaged several times by separatist movements in Russia. In winter of 2002-2003 the gas supply to Armenia was completely lost for an extended period of time, which resulted in depletion of Armenia's entire fuel reserves (natural gas and fuel oil) for power generation.

The lack of diversity of natural gas supply and transportation has put Armenia's national security at risk. Therefore, to minimize this risk, the GoA decided to move forward with the construction of the Iran-Armenia gas pipeline, which is scheduled for completion in late 2006 to early 2007.

Several studies have been conducted regarding the expansion and rehabilitation of both the natural gas transmission and the gas storage facility. The studies point out that diversity of supply sources and routes furthers national energy security, enhances gasification of the country, and may provide for transit fees. However, they also point out that the Iran-Armenia pipeline can not be economically justified for the electric power production purposes only; nor can the Armenian consumers afford the rate impact of the full cost of this pipeline.

c. TRANSPORTATION (ROADS, RAILROADS, AIRPORT)

New generation resources will require the ability to bring in large pieces of equipment via railroad, airplanes or roads. The lack of transportation infrastructure in Armenia is a large concern and needs to be addresses when new generation resources are selected.

Before a new nuclear plant can be built to replace ANPP, major upgrades to the transportation routes through Georgia or other neighboring countries and/or restoration of rail access through Azerbaijan should be evaluated. Much of the equipment and building materials needed to build a new nuclear plant are too large and/or too heavy for transport over the existing railroads, bridges, and tunnels of the "northern route" through Georgia. The only existing useable transportation route is the railroad through Azerbaijan. Transportation of equipment could be a problem even for non-nuclear power plants.

There are some possibilities to bring large pieces of equipment in large airplanes, but the Zvartnots airport may require some rehabilitation before it can accommodate large planes. Once the equipment arrives at Zvartnots, the ability to use the transportation infrastructure within Armenia still needs to be examined.

d. WATER RESOURCES

Water is used in hydropower plants for power generation and in thermal and nuclear plants for steam production and cooling. The passage of the new Water Code (2002) requires water permits, payments for water use, and protection of water quality. The Water Code also states that international water boundaries are the property of the State. New plants should be located where there is an easy access to sufficient water resources and the necessary governmental permits can be obtained.

The 2005 LCGP assumes that the payments for water use are very small as compared to other costs and will not impact the results of the analysis. However, charges for water use by power plants should be passed on to customers through retail rates, otherwise, sufficient funds will not be available to cover operation and maintenance costs, salaries or profits, thereby reducing the economic viability of the power plants.

e. AIR EMISSIONS AND OTHER ENVIRONMENTAL IMPACTS

New thermal plants should employ the latest technique/technology for NOx reduction. Gas-turbine technologies are available and are being used to limit NOx emission to two (2) parts per million (PPM). The growing smog problem in Yerevan is primarily due to the increased use of vehicles since Armenia's electric power needs are primarily met by ANPP. Smog is created by reaction of NOx (from different sources) volatile organic compounds (VOCs) from vehicles, paints and solvents. Sunlight and hot weather catalyzes a complex series of reaction in which NOx and VOCs react to form what is generally referred to as photochemical smog.

The value of non-emitting power plants (nuclear, hydro, or wind) is higher if the environmental externalities are calculated; particularly if CO_2 credit, Clean Development Mechanisms, and/or Join Implementation (JI) is considered and implemented. However, environmental benefits must be considered along with other goals and objectives of the Armenia's energy strategy adopted in June 2005 – diversification of energy resources, energy security, and affordability by the people of Armenia.

3.3.6 Decommissioning Options for the ANPP and Costs

According to the International Atomic Energy Agency (IAEA), decommissioning "is the actions that are taken to allow the removal of some or all of the regulatory controls that have been placed on a facility that has used radioactive material. These actions include both administrative and technical actions that must be accomplished to show that the facility that has used radioactive material can be released for unrestricted use or otherwise reused".

The U.S. Nuclear Regulatory Commission uses a more ambitious definition involving removing a reactor safely from service and reducing residual radioactivity to a level that allows a site to be released for unrestricted use, thereby allowing license termination.

Both definitions contemplate three basic methods of decommissioning a nuclear power plant:

- Immediate Dismantlement (DECON): The facility is decontaminated and radioactive wastes are treated, packaged and removed to an appropriate waste storage or disposal site.
- Entombment (ENTOMB). Radioactive structures, systems, and components are encased in a structurally long-lived substance, such as concrete, at the facility.

- Safe Storage (SAFESTOR): The facility is placed in a safe, stable condition and maintained in that state for an extended period, followed by decommissioning by DECON or ENTOMB.

Decommissioning activities, especially technical and financial planning, is generally taken into account during the original plant design. Since this was not done in Armenia, there is an urgent need to establish the standards that Armenia should adopt for the site, when the operations cease at ANPP, and develop a realistic decommissioning plan for 2016 when the plant reaches the end of its designed life.

Decommissioning costs [excluding Spent Nuclear Fuel (SNF)] will not increase greatly with continued operation of the plant. Most decommissioning expense is created in the early years of reactor operation, when the piping and other reactor internals become contaminated. Additional exposure, assuming normal operation, can increase the number of workers needed for decommissioning, but the amount of material to be disposed of does not increase greatly.

The 2005 LCGP analysis included the evaluation of decommissioning options for the ANPP. A detailed evaluation of the decommissioning options and related analysis is presented in Appendix A. Because the Armenian government has not established a date for the shutdown of ANPP, this study investigated decommissioning cost for plant shutdown at the end of 2009, 2015, and 2035.

A major factor in the cost for decommissioning is the cost for disposal of radioactive waste. In the case of ANPP, an existing low-level waste storage facility is located near the plant. However, this facility would have to be converted to a near-surface disposal vault and expanded substantially to allow disposal of all of the decommissioning waste. Alternatively, a new near-surface disposal vault facility could be constructed on the ANPP site or elsewhere in Armenia. Another alternative may be to use the ANPP reactor buildings as the final disposal vault for the radioactive waste.

The cost of final disposal of SNF, while not usually included in decommissioning costs, represents a substantial future cost for ANPP that is currently unfunded. SNF has been accumulating at the plant since it was restarted in 1995. Returning the SNF to Russia for reprocessing is the only technically and economically feasible disposal option. However, this option is not currently available and the timing and cost cannot be estimated accurately until a plan for SNF disposal is defined. US regulations currently prohibit receiving spent fuel from other countries. Canada is still developing plans for long term disposal in Whitteshell. Britain, France, and Russia have accepted spent fuel from other countries for reprocessing, but all three require that the products and wastes from reprocessing be returned to the customer. Although Russia is considering changes in the law mandating this approach, Russian fuel reprocessing facility at Mayak is currently closed.

A range of estimates for potential Russian fuel disposal fees was developed from review of the literature. The cost for disposal of the current spent fuel inventory is potentially larger than the plant's decommissioning cost. The spent fuel disposal fees are estimated to range from 382 to 631 million in 1999 dollars.

Table 3.2 presents estimated decommissioning costs assuming plant shut down at the end of 2015. This table shows that the scenarios involving SAFESTOR have a lower present value even though the estimated cost is higher. This is because a large portion of the decommissioning cost is deferred 40 years into the future. However, it should be noted that the escalated present value results are very sensitive to the difference between the assumed escalation and discount rates. The SAFESTOR scenarios have a much

greater financial risk if escalation in construction costs over the next 50 years is higher than the general rate of inflation reducing the difference between the escalation rate and the discount rate. With escalation rates of three percent, the SAFESTOR scenario becomes more expensive on a present value as well as an absolute basis.

Table 3.2 Decommissioning Costs for 2015 ANPP Shutdown (Millions of US Dollars)

Decommissioning Scenario	Estimated Cost	2016 Present Value
DECON	298.1	241.4
SAFSTOR/ DECON	513.8	186.9
ENTOMB	248.8	206.8
SAFESTOR/ENTOMB	446.8	176.4

The Armenian government has adopted an amendment to the “Law on the Safe Use of Nuclear Energy for Peaceful Purposes”. This amendment reaffirms sections of the Republic of Armenia Energy Law that requires a portion of the ANPP electricity sales be set aside to fund plant safety, security, and other upgrades as well as decommissioning. Charters and decrees to define the amounts to be collected for decommissioning and the process for collecting and managing the funds are currently being developed.

Internationally, a commonly used funding method is an electricity rate surcharge on the kWh tariff on nuclear plant generation to collect the needed decommissioning funds over the remaining life of the plant. The information from the cost estimates was used to estimate the surcharge needed to accumulate the necessary decommissioning funds over the period starting in 2006 and extending through 10 years after plant shutdown, based on shutdown in 2009, 2015, or 2035. The results show that, for shutdown in 2015 or earlier, the surcharge for decommissioning would result in a 30 to 70 percent increase in the price of ANPP generation.

An alternative approach would be to put a surcharge on all electricity consumed in Armenia. Based on shutdown in 2015, the surcharge for decommissioning would increase the average electric rates by about 7 percent.

Several scenarios were investigated to estimate the surcharge required to pay for future disposition of spent fuel. These scenarios covered variations in ANPP shutdown date, SNF disposal date, and escalation in disposal fees. For these scenarios, the surcharge to fund SNF disposal range from $1.7 to 27 million per year. The results demonstrate the sensitivity of the cost for spent fuel disposal to assumptions on the timing and escalation of disposal fees. For scenarios involving significant escalation in disposal fees, the surcharge needed for SNF disposal is much higher than the decommissioning surcharge. Determining the appropriate surcharge for SNF disposal will require defining a disposal plan.

The ENTOMB scenario appears to be the preferred approach for decommissioning of ANPP. Besides being the lowest in total cost and shortest schedule, ENTOMB has a number of other technical, regulatory, and social benefits which are discussed in Appendix A.

3.3.7 Regulatory and Decommissioning Fund Issues

Normally, decommissioning and spent fuel disposal, though interrelated, are treated separately, but for Armenian regulatory purposes both are large future liabilities for which insufficient money has been collected.

Decommissioning standards and safety standards are set by the Armenian Nuclear Regulatory Authority (ANRA), while the rate setting is governed by the Public Services Regulatory Commission (PSRC). Adequate funding of a nuclear plant is a safety issue as well as an economic issue, so these agencies need to work cooperatively to assure that adequate funds are available to decommission the plant to the standards required by Armenian law and policy, and international norms and standards.

ANPP's 2004 tariff was about $.013/kWh and it is about the same for 2005 and the current decommissioning and SNF disposal allowances in Armenia's electric tariff is about $1.2 million per year.

Assuming that: the surcharge begins in 2006; the ANPP is retired in 2015; collection of the funds through 2025; and the completion of decommissioning and SNF disposal by 2027, the Armenian electric tariff increase needed to cover costs of decommissioning plus spent fuel disposal is approximately $.01/kWh (22%) before VAT or about $24 million per year for the next 20 years.

The main Characteristics of a dedicated fund are that it:

- Must be adequate to cover decommissioning costs, taking into account reasonable investment earnings;
- Should be "ring fenced" to be sure that it can only be spent for decommissioning and spent fuel disposal;
- Should be managed transparently and conservatively by a qualified board of trustees independent of the utility answerable both to the nuclear regulator and to the PSRC (donors may require some form of international management or oversight for their contribution to the fund);
- Should be audited annually by a creatable and independent international auditor in accordance with international accounting standards and international audit standards;
- Should invest conservatively.

Lessons learned from other countries are that the dedicated funds are likely to be misused unless the safeguards are very strong and independent of government. The examples of misused funds are numerous (several billion dollars of the U.S. spent fuel funds have been used for general budget; the French and British funds collected for decommissioning was spent by the utilities on acquisition programs in other countries; earnings on German funds count toward utility profitability), however, dedicated independent funds in Finland, Spain, and Sweden are a good example of how the funds should be managed.

Donors have played a major role in providing decommissioning support. Funds totaling more than $700 million have been created at EBRD for instances in which Europe has negotiated for plant shutdown (Lithuainia, Bulgaria and Slovakia). This assistance usually takes the form of a separate fund managed by EBRD, with funds overseen by a committee that approves the expenditures.

The consequences of doing nothing and holding ANPP tariffs below the costs of needed safety improvements could create potential safety hazards due to lack of adequate funding. Therefore, Armenia should: a) establish a dedicated and realistic decommissioning fund based on an electric rate surcharge; b) Develop a firm decommissioning plan and schedule; c) Develop a spent fuel strategy and determine its relationship to decommissioning; d) Develop cost estimates for SNF disposal and decommissioning; e) Negotiate with potential donors; f) Include realistic decommissioning and spent fuel disposal costs in assessments of Armenia's future power supply options.

3.3.8 Plant Life Extension Cost Estimate

An alternative to the construction of new generation capacity is the life extension of the ANPP beyond 2015. Russian experts believe that the service life of similar units may be extended for about 15 years, i.e. until 2031 for ANPP. The ANPP experts/ staff are exploring the feasibility of extending the life of the plant by 20 years to 2035. Life extension projects are being pursued at similar design plants at Novovoronezh and Kola NPPs in Russia.

Plant life extension requires a systematic and comprehensive assessment of age related degradation mechanisms for all systems, structures, and components at ANPP. In the US, where life extension assessments of nuclear plants are now fairly routine and are supported by a large industry database, the average cost of a license renewal application is about $10-12 million. The assessment often identifies many components that must be repaired or replaced to ensure safe operations in the years of extended life. Examples of high cost plant equipment/component that needs replacement are: steam generator, pressurizer, reactor vessel head, and plant cabling. For VVER 440 type reactors, experience at other plants indicates that annealing of the reactor vessel to reduce radiation damage to the steel may be required. The total cost of these life extension upgrades can not be determined with any certainty without extensive analysis. However, it is estimates that ANPP life extension costs will be between $100 and $300 million and most of this money would need to be spent in 2013-2018 timeframe, for a life extension beyond 2015. For the 2005 LCGP analysis, a life extension cost of $50 million per year from 2013 to 2018 is assumed.

3.3.9 Safety, Reliability, and efficiency Project Expenditure at the ANPP

The ANPP is an older unit of a type that would not be licensed today. Comparable units in Bulgaria and Slovakia have been or will be closed as part of the requirement for entry to the European Union. ANPP's continued safe operation requires implementation of a number of generic safety upgrades that need to be accomplished between 2005 and 2010. These safety issues are described in IAEA-TECDOC-640, *Ranking Of Safety Issues For WWER-440 Model 230 Nuclear Power Plants*, 1992. The IAEA report ranks safety issues into four categories. Categories III and IV are issues of high safety concern, where immediate attention is required. Issues in Category II are also of safety concern, representing degradation of defense in depth, when action is required to resolve the issue. Issues in Category I reflect a departure from recognized international practices that should be addressed as part of actions to resolve higher priority issues.

The list of ANPP safety projects includes 24 Category III, 19 Category II, and 5 Category I projects. For 18 of these projects, some or all of the costs are expected to be provided by donor assistance from USDOE, TACIS, or DTI. In addition, USDOE has recently offered an additional $4 million for safety improvements in 2005-2006 timeframe. However, for many of the projects, the donor assistance is limited to analytical or design work and does not include the cost of hardware or installation. For example, in 2005, DTI will be funding a project for developing an equipment qualification program but the cost for qualification

testing and replacement of equipment, estimated to be as much as $5 million, is not included in the DTI project scope. In other cases, the safety upgrade projects involve analysis of the adequacy of existing plant systems. The results of these analyses may indicate the need for equipment modification or replacement that is not included in the scope of the upgrade projects.

The costs to implement the identified ANPP safety upgrade projects were estimated based on experience on similar projects in the US and cost data for similar projects at other VVER 440 plants reported in the literature and are presented in Appendix A-2. The total cost for all projects that will not be supported by donor assistance is estimated to be between $22 and $94 million. If these safety upgrade projects are to be accomplished over the next five years (i.e., completed by the end of 2010) an average of $4.5 to 24.5 million per year in capital funds will be needed.

In addition to nuclear safety upgrade projects, ANPP will require other capital projects to ensure reliability, thermal efficiency, and personnel safety. For example, plant management has indicated that renovation of the main condenser could improve plant efficiency and electrical output significantly at a cost of $1.5 million. Based on the age of the plant, it can be expected that other high cost projects such as feed water heater replacement, turbine controls upgrade, or plant instrument modernization will be needed over the next several years to ensure reliable performance of the plant. Other capital projects are needed to manage radioactive waste that is accumulating at the plant and for spent fuel storage for operation beyond 2009. The cost of these non-safety capital projects has not been estimated. Operation beyond 2009 may also require specific license approval by ANRA. The ANRA process and requirements for licensing are currently being developed. However, it can be anticipated that additional safety upgrades may be needed beyond 2009 to comply with license commitments.

For the 2005 LCGP analysis, a cost of $24 million per year for safety upgrade, reliability and efficiently projects is assumed from 2006 though 2010.

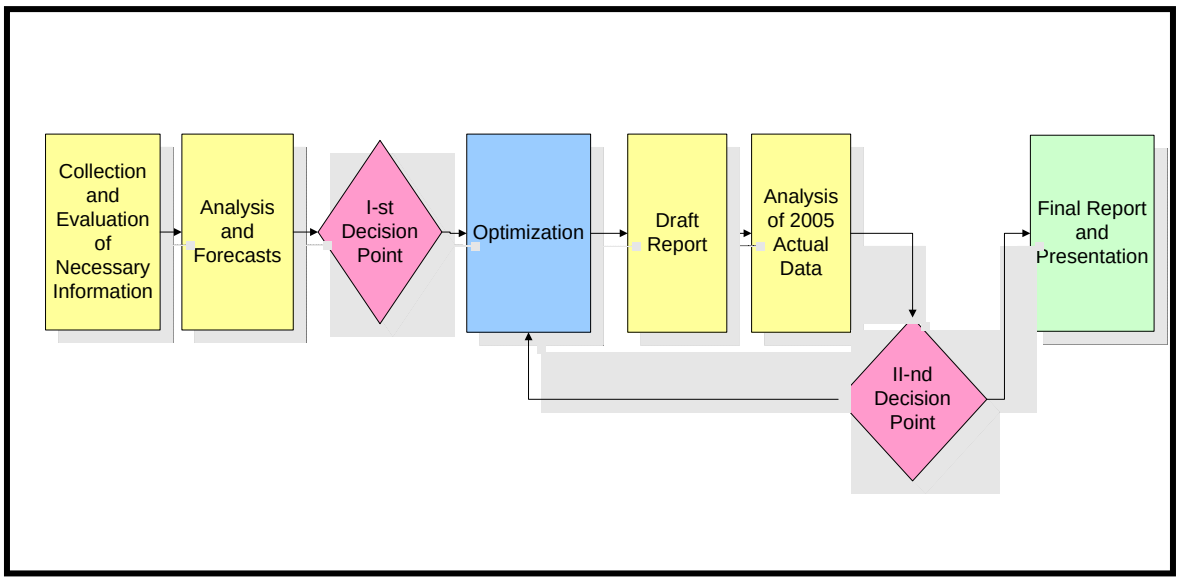
4.1 2006 LCGP APPROACH AND PROCESS

LCGP 2006 was developed as an update of LCGP 2005. An assessment of forecasts, assumptions, and scenarios revealed minor or no changes to the results; hence there are no changes in some section of this report as compared with the LCGP 2005.

A work plan, including an overall process along with milestones, was developed for the preparation of the 2005 LCGP. The 2005 LCGP team included Ministry of Energy, Public Services Regulatory Commission, Ministry of Finance & Economy, Ministry of Trades and Economic Development, and PA Consulting Group. Figure 4.1 depicts the overall approach for the development of the 2005 LCGP.

The areas and analysis that required revision for LCGP 2006, due to latest changes since the development of the LCGP 2005, did not require extensive GoA agencies involvement and were mostly prepared by the MoE with support from PA Consulting Group.

Figure 4.1 Overall Approach

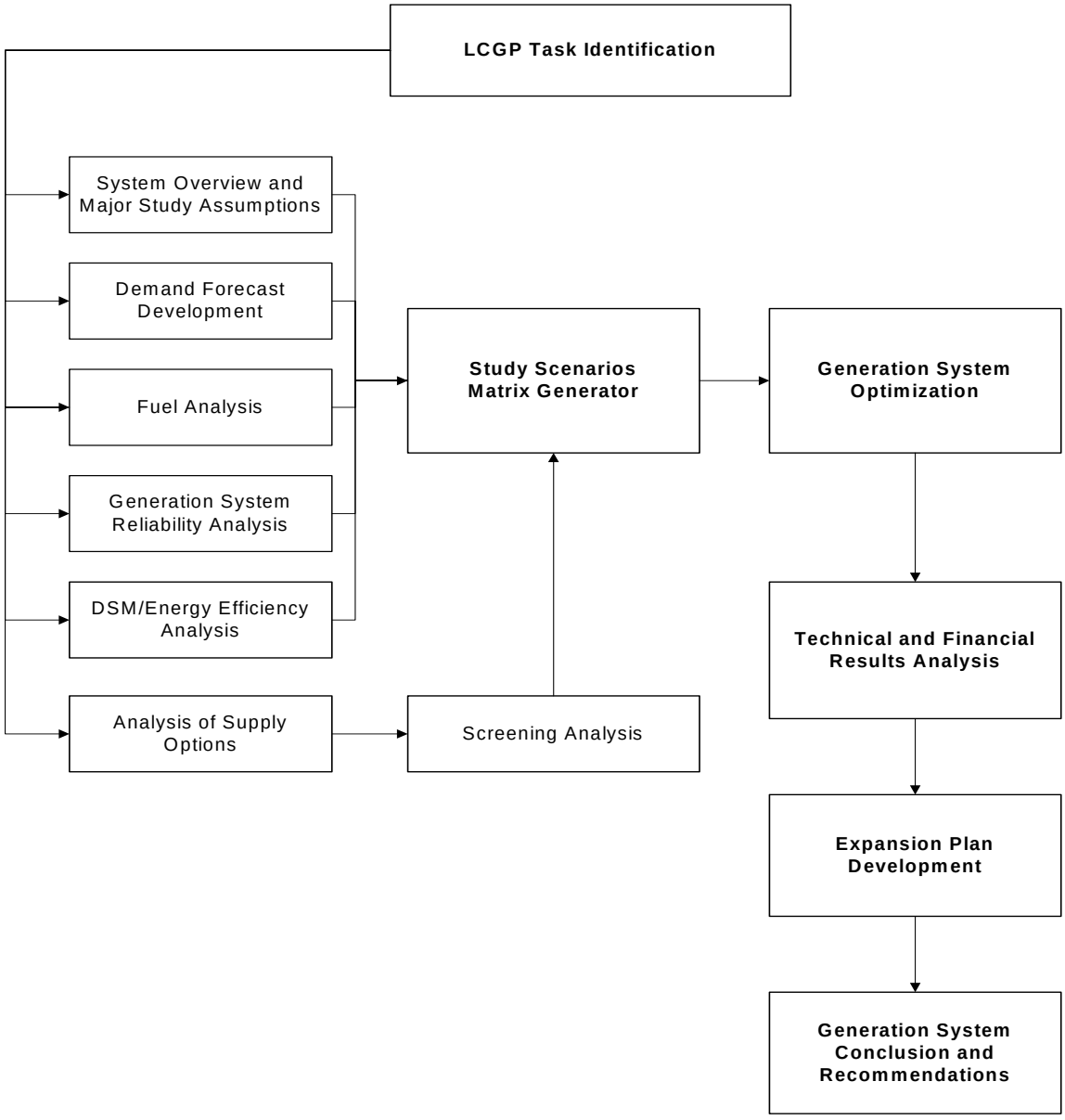


The 2002 LCP and 2005 LCGP laid the foundation of the LCP process for Armenia and the 2006 LCGP builds upon the experience from the earlier plans and from the examination of the last three years data. Figure 4.2 presents the process for this study.

Upon the identification of major tasks, the following activities commenced:

- Forecast of economic and financial factors;
- Forecast of the electric system peak and energy forecast;
- Fuel analysis;
- Generation system reliability analysis;
- Demand-side management analysis; and,
- Supply options and screening analyses.

Figure 4.2 2006 LCGP Process



4.2 DATA GATHERING

Power generation planning requires a wide spectrum of accurate data on different aspects of the electric power system. The quality of the planning results is very dependent on the quality of input data. In this respect this study faced a great challenge, since both availability and reliability of the available data are far from satisfactory. In most cases, the data that was obtained needed additional processing, validation, and comparison with data from other sources.

In many cases the data and results of other studies and reports, performed previously by other agencies, were used (including, but not limited to: IAEA Energy and Nuclear Power Plan Study, 2004 (IAEA – TEDOC – 1404) and TACIS Nuclear Study Program, 2003. This along with data sources for 2002 and 2005 LCGP constituted a large part of the initial

data set. However, in many cases the data were found to be outdated and/or contained inconsistencies. Due to that fact, considerable time was spent on validation of data, so that the most accurate data available could be used for this analysis. Furthermore, a number of issues were evaluated as part of this study, such as ANPP decommissioning, life extension, spent fuel storage, safety upgrade projects, and reliability and efficiency project costs, which are presented in Appendix A. In addition, a study was conducted to assess the potential of the renewable resources (wind, biomass, and solar energy). The results of these studies are discussed in the following sections and are presented in Appendix B.

The information on existing hydropower plants was collected mostly from previous studies and from hydropower plants (HPPs). Previous studies provided data on the actual physical condition of existing plants and assessments of future plant sites. This included information on turbine wear, stream-flow projections and sedimentation, and data for potential plant sites.

Historical data on power plants output, the system peaks and hourly loads, and the exchange information on international connections (exports and imports) were obtained from the National Dispatch Center. Also, information on prospective projects was obtained from previous studies, which was updated for this analysis.

4.3 FINANCIAL ASSUMPTIONS

IPM model was used for analyzing the supply options to meet the energy and capacity requirements for the study period. Two financial inputs are utilized by the IPM model: annual inflation rate and the estimates of cost of capital.

4.3.1 Inflation

Forecast of the annual inflation rate for each year over the next 20 years seems almost impossible and Armenia's monetary policy has not been established for such a long term horizon. Also, other factors influencing the inflation rate in Armenia are of low predictability, and 20-year predictions would be unworthy of consideration. Furthermore, in 2003, pursuant to Poverty Reduction Strategic Program, the Central Bank of Armenia set a target for annual inflation at 3%. Actual results of 2003 and 2004 surpassed the target, and at yearend inflation amounted to 4.5% and 6% respectively. Therefore, this analysis assumes an annual inflation rate of 4.5%, the mid-rage of the target and the highest rate experienced in the last two years.

4.3.2 Cost of Capital Estimates

Three main scenarios regarding weighted average cost of capital were analyzed in the LCGP 2005: 8.48%, 12.7% and 14.9%. It was also assumed that the financing for the construction of new nuclear power plants might be obtained from international organizations on privileged terms, while for other generating technologies such privileged financing would not be available in general, apart from the construction of a 225 MW CCGT at Yerevan TPP site, which would be financed by JBIC at 0.75% interest per annum. Thus, one scenario of LCGP 2005 might contain a set of generation technologies, financed at different non-uniform interest rates, based on tied credits.

It was assumed that 100% financing of the new nuclear plant can be obtained via state guaranteed debt at 8.48%, when for the other generating technologies such financing would not be available and it would be necessary to raise equity capital. As a result, the weighted average cost of capital might grow for thermal and hydro technologies up to 12.7% and 14.9% depending on the potential structure of capital.

Since the development of LCGP 2005, conditions of the financial markets have also changed. First, the difference in interest rates between long-term and short-term debt has practically disappeared mainly due to the absence of the latter (for the purposes of least cost planning). The US government ceased issuing 30 year treasury bonds, which served as a good proxie for valuation of a long-term debt at international capital markets.

The situation in Armenia is somewhat different: the country has never had a long-term money rate (20 to 30 years) and has no experience of its pricing. At present, the longest bond traded by the Central Bank of Armenia (CBA) has 365 days maturity period.

Nevertheless, the CBA publishes the yield curve, which has information for longer terms. Table 4.1 presents the data relevant to the present conditions, and indicates that the interest rate reaches 8% for a 10 year loan at the primary market.

Table 4.1 VOLUMES AND YIELDS ON LONG-TERM GOVERNMENT COUPON SECURITIES SOLD IN THE PRIMARY MARKET[1,2]

Period		Sold (mln drams)	Average nominal yield (%)	Minimum interest rate	Maximum interest rate	Standard deviation
2004	September	1500.0	9.2	9.2	9.2	0.0
	December	1200.0	9.3	9.3	9.3	0.0
2005	March	1500,0	6,9	6,9	6,9	0.0
	May	1000.0	6.7	6.7	6.7	0.0
	June	1500.0	8.1	8.1	8.1	0.0
	September	1500.0	7.7	7.7	7.7	0.0
	December	1160.0	8.8	8.8	8.8	0.0

1 Source: the CBA.

2 All issues of T-bills with maturity of the stated ranges are included. The amount of T-bills sold is equal to the amount of all securities in the range sold. Yield is calculated as the weighted average of the given securities.

Assuming that inflation rate would remain as predicted at 3% per year, it yields 4.8% a year for a real cost of capital (0.08/1.03=1.048). These estimates hold for a 10 year period. Linear extrapolation for a 20 and 30 year periods, which are the periods comparable with the duration of a least cost generation plan horizon, produces 9.6% and 14.4% respectively. Though these figures may appear somewhat exaggerated, they confirm that the previous estimates of potential cost of capital at the level of 12.7% and 14.9% remain reasonable for the consideration in the least cost plan.

Also, the tied financing for nuclear power plants that was considered in the LCGP 2005 was removed, thus 2006 LCGP Update is based on uniform weighted average costs of capital for all technologies(8.48%, 12.7% and 14.9%).

4.4 ELECTRICITY DEMAND FORECAST

The actual electricity demand in 2005 was within the forecasted range, which was used in LCGP 2005. Therefore, the LCGP 2005 demand forecast was used for the LCGP 2006 study.

Demand for 2005 to 2025 is forecasts based on recent historical energy consumption data. The reason for relying on the historical data rather than using econometric modeling to forecast future demand is that the energy demand growth can not be completely attributed to economic growth. While GNP has increased by over 60% since 1999 the electricity demand has only grown by less than 1%. Details of the load forecasting process can be found in Chapter 5 and Appendix D.

4.5 SYSTEM RELIABILITY

For 2000 and 2002 LCP, the calculations of the reserve margin requirement were performed using sophisticated computer programs, based on probability analysis.

Given the age of Armenia's generation units and due to lack of investment and proper maintenance of the sector facilities, the probability of failure has increased over the years. This fact was also noted in the IAEA report. Therefore, for this study, a reserve margin of 30% of annual peak load was used.

4.6 FUEL ANALYSIS

Fuel analysis was focused primarily on identifying potential fuel sources for power generation and forecasting its consumption and price escalation patterns. Fuel supply analysis is one of the most important components of input data for modeling purposes.

Natural gas has been identified as the only alternative to nuclear energy for power generation in the foreseeable future. The primary reason is that other energy sources such as hydro and wind can not meet a substantial energy need of Armenia and/or are not available on demand when needed.

Given the electric load forecast, aside from security of supply stand point, the existing gas pipeline system of Armenia is more than adequate to transport the required natural gas during the study period regardless of the retirement date of the ANPP. Currently, the Iran-Armenia pipeline is under construction, which is expected to be completed in late 2006 to early 2007, which may address the supply security issue.

Three natural gas price scenarios were considered for LCGP 2005. The gas price for Armenia, assuming average price increase over the forecasting period, was projected to increase: for the High Growth scenario, 5.63% per year at the border and 4.91% per year for the power plants; and 4.88% and 4.22% for Moderate Growth Scenario respectively.

The fuel price forecast for LCGP 2006 was updated according to the new Russia-Armenia agreement. The price of imported natural gas from Russia in 2006 will equal $110 per thousand cubic meter (tcm), which is more than 100% higher than the 2005 price of $54 per tcm. This price increase introduces a substantial change in the forecast and the relative percentage of fuel price forecast.

Since the major assumptions driving the gas price, aside from political aspects and the increase from $54 to $110 per tcm, remains the same, only one fuel price increase scenario (2.37% per year) was considered for LCGP 2006.

Detailed analysis related to fossil fuel forecast is presented in Appendix E.

The nuclear fuel forecast was based on official reports and publications and is assumed to increase at 3% per year for the next 20 years and is presented in Appendix A.

4.7 SCREENING ANALYSIS AND SUPPLY OPTIONS

Screening analysis is an essential part of the overall modeling process. Screening reduces the number of supply options to be considered at the stage of computer modeling, reducing computational time and increasing the optimization accuracy. 2006 LCGP included a screening analysis of several new technologies/projects including:

- New Gas-Fired Combined Cycle Power Plants (225 MW and 400 MW capacities)
- Gas-Fired Gas Turbine (75 MW capacity)
- Nuclear Units [AP-1000 (USA), two units CANDU 6 (Canada), ACR-1000 (Canada), VVER-1000 (Russia), and EPR (France/Germany)]
- Hydro Plants (70 MW at Shnokh, 140 MW at Megri and 68 MW at Lori-Berd)

Also, to gain a better understanding of the proposed rehabilitation/ reconfigured projects, they were compared to new technology alternatives. As noted, this analysis serves to reduce the number of resource alternatives that need to be included in the optimization phase of the least cost generation planning process.

The screening process takes into account levelized *capital costs*, both *fixed and variable O&M costs*, expressed in dollars per kW at various capacity factors for each alternative technology/project. The objective is to select the lowest cost units within specific bands of capacity factors as candidate resources for inclusion in the optimization phase of the study.

It is important to recognize that screening analysis is performed only as a preliminary step of overall optimization process and its primary goal is to reduce computational time rather than providing an answer for the technology to be chosen for further and more detailed considerations. The screening analysis for the this LCGP is provided in Appendix F.

4.8 OPTIMIZATION PROCESS

As in the earlier analysis, the IPM™ (Wholesale Integrated Planning Model) model was used for the 2006 LCGP to perform both dispatch and financial analysis. The IPM™, developed by ICF Consulting Inc., is a long-term optimization dynamic planning model that uses linear programming formulation to select investment options and to dispatch generation and load management resource to meet overall electricity demand and energy requirements. The dynamic nature of the model implies the capability to use forecasts of future conditions, requirements, and alternative characteristics to make decisions for the present time.

The model is extensively used throughout the world by private companies and government agencies in the areas of integrated resource planning, detailed modeling of dispatch, strategic planning, options assessment, optimization of utility operations under system-wide constraints, estimation of avoided cost, and analysis of uncertainty.

IPM™ is a fully integrated software package, consisting of a number of modules. All modules are governed by a single main program driver that automatically initiates operation of each of the modules. The IPM™ core module writes the linear programming task in the output file that is processed in the next step in the linear-programming solver (XPRESS MP by Dash Associates, Inc.).

The model minimizes the present value of the total costs of the simulated power system over the entire time horizon and includes:

- Production cost of electricity;
- Capital investments into new power plants during the planning interval years. The capital investments are included in equivalent form as annuities that are calculated as part of total investment at fixed payments on capital;
- Costs associated with electricity purchases and sales outside the domestic market.

The major groups of constraints include:

- Meeting the demand for electricity in each year, season and load segment;
- Maintaining necessary level of reliability;
- Inter-regional transmission capability;
- Power plants' dependable capacity, maintenance schedules and forced outage rates;
- Water availability for hydropower plants;
- Fuel availability.

Minimization of total production and capital costs under the given set of constraints ensures objective, commercially optimum dispatch (utilization) of available generating resources to meet balance conditions, as well as the commissioning of new resources in view of service-life efficiency.

The full cost of ANPP decommissioning is not included in the analysis. The decommissioning costs need to be recovered regardless of the date of the ANPP retirement. The cost, however, should be collected through an increase in retail tariffs to ensure that the funds are available to decommission the plant in the future. Since the existing electric consumers have the benefit of the low-cost energy from the ANPP, they should bear the cost of decommissioning the plant. Otherwise future rate payers will have to bear the cost.

4.9 INVESTMENT PLANNING

The IPM optimization modeling provided results in terms of optimized capacity and investments requirements for the time interval of 2006-2025. Optimizing costs over 20 years, instead of only a few years, allows for the consideration of more options and for a clearer definition of optimum long-term solutions for the power system's development.

However, the IPM™ multi-year optimization approach does not provide integral unit solutions when optimizing the schedules of capacity additions due to a specific linear programming technique that it employs. To "convert" these non-integral MW-based initial model's outputs into the discrete unit-based capacity additions, subsequent analysis using iterative IPM™ model runs is required.

Once an optimum solution or set of alternative solutions has been identified, the IPM™ model can be reapplied on a year-by-year basis, to provide output in terms of annual capacity additions. These results can then be used to develop annual capacity expansion plans and capital investment forecasts. However, the model was constrained to require that specific generating plants, or major portions of generating plants, be commissioned in specific years. The commissioning dates were established by aggregating the gradual commissioning sequences from the original optimized results into single mid-span years.

The IPM model was then run again to verify that the adjusted results conformed to the original optimized model results. Multiple IPM™ model runs were conducted iteratively to develop a set of plant commissioning dates that closely reflected the optimization results in terms of life-cycle Net Present Value (NPV) cost.

The annual commissioning schedules were then used to determine annual capital expenditures that will be needed to meet the required start-up dates. This was done by entering the annual construction costs for specific plant facility into a spreadsheet, and tallying the costs for all of the plants on a year-by-year basis.

4.10 SENSITIVITY ANALYSIS

The sensitivity analysis was performed to assess potential impacts of electricity load forecast, Armenian Nuclear Power Plant decommissioning date (2016 and life extension to 2035), fuel price forecast, and discount rate on Armenian generating capacity expansion plan in terms of technology, timing, and economic costs.

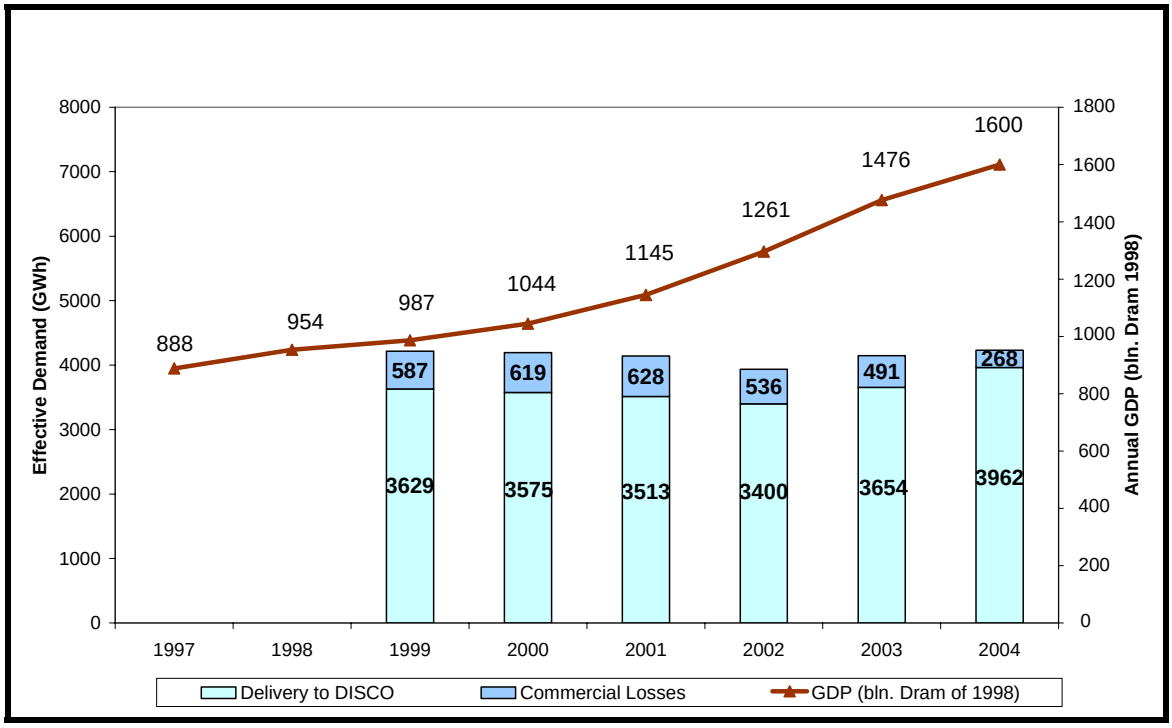
One strategic option was examined for this analysis, which included the construction of Shinokh and Lori Berd hydro power plants, completion HTPP #5, and construction of two CCGT units at YTPP (one financed by JBIC and the other at commercial rate), to determine the potential economic penalty to consumers for the development of domestic energy sources.

5.1 LOAD FORECASTING ANALYSIS

5.1.1 Introduction

This chapter summarizes the results of the energy and demand forecast from 2005 to 2025, which was developed based on recent historical energy consumption data. One reason for relying on the historical data rather than using econometric modeling is that as shown in Figure 5.1 the demand growth can not be completely attributed to economic growth. The detailed analyses and explanations of these forecasts are presented in Appendix D of this report.

Figure 5.1 Economic Development and Energy Consumption



The forecasting procedures involved linear modeling using historical data. The results were then adjusted to account for abnormalities in the historical data. Finally, three – high, reference, and low – growth scenarios where considered to account for potential variations in the overall economy. The High Growth Scenario is characterized by 4% growth in energy demand and 3.4% growth in peak load. The Reference Growth Scenario assumes 3.1% growth in energy and 2.7% growth in peak load demand, while the Low Growth Scenario assumes 1.9% growth in energy demand and peak load. The details of the forecasting approach and the results are presented in Appendix D.

5.1.2 Major Results

The results for all scenarios are summarized and shown in Tables 5.1 and 5.2.

Table 5.1 Domestic Energy Forecast (GWh)

Year	Reference		High		Low	
	Domestic Needs	Gross Generation	Total Domestic Needs	Gross Generation	Total Domestic Needs	Gross Generation
2005	4150	5629	4150	5629	4150	5629
2006	4441	5909	4515	6002	4388	5841
2007	4749	6199	4871	6352	4599	6012
2008	5098	6531	5226	6688	4768	6124
2009	5379	6877	5546	7082	4936	6331
2010	5662	7227	5857	7465	5100	6533
2011	5934	7562	6155	7833	5255	6724
2012	6172	7855	6469	8219	5409	6913
2013	6356	8082	6759	8576	5573	7115
2014	6532	8299	7058	8945	5689	7258
2015	6675	8475	7347	9301	5791	7385
2016	6801	8630	7606	9620	5876	7488
2017	6927	8786	7873	9948	5958	7590
2018	7067	8958	8145	10282	6043	7694
2019	7207	9131	8409	10608	6119	7788
2020	7334	9289	8650	10906	6193	7879
2021	7462	9446	8897	11209	6263	7965
2022	7587	9601	9141	11510	6333	8051
2023	7738	9787	9383	11808	6401	8136
2024	7893	9978	9621	12101	6472	8223
2025	8084	10170	9862	12398	6540	8306

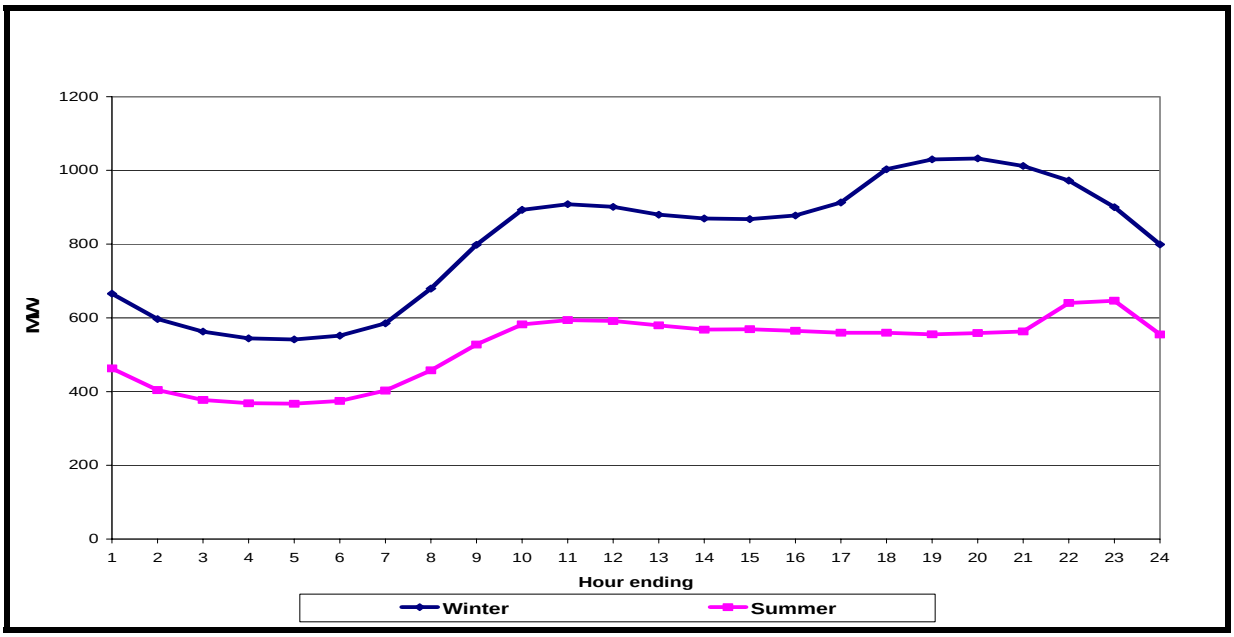
Projected generation capacity is sufficient to meet potential energy export demand to neighboring countries, when excess energy is available. Any capacity expansion/addition costs strictly for electric power export is expected to be recovered through export tariff and is not expected to impact the result of this study.

Table 5.2 Peak Load Forecast (MW)

Year	Reference	High	Low
2005	1293	1293	1293
2006	1359	1379	1346
2007	1428	1458	1389
2008	1507	1532	1415
2009	1597	1618	1465
2010	1587	1699	1514
2011	1666	1775	1559
2012	1741	1854	1604
2013	1805	1925	1652
2014	1850	1997	1684
2015	1892	2064	1711
2016	1949	2121	1733
2017	1974	2179	1753
2018	2003	2238	1774
2019	2031	2293	1793
2020	2055	2341	1810
2021	2079	2390	1826
2022	2102	2437	1842
2023	2131	2482	1857
2024	2162	2525	1873
2025	2198	2569	1902
Average Annual Growth rate, %	**2.634**	**3.398**	**1.927**

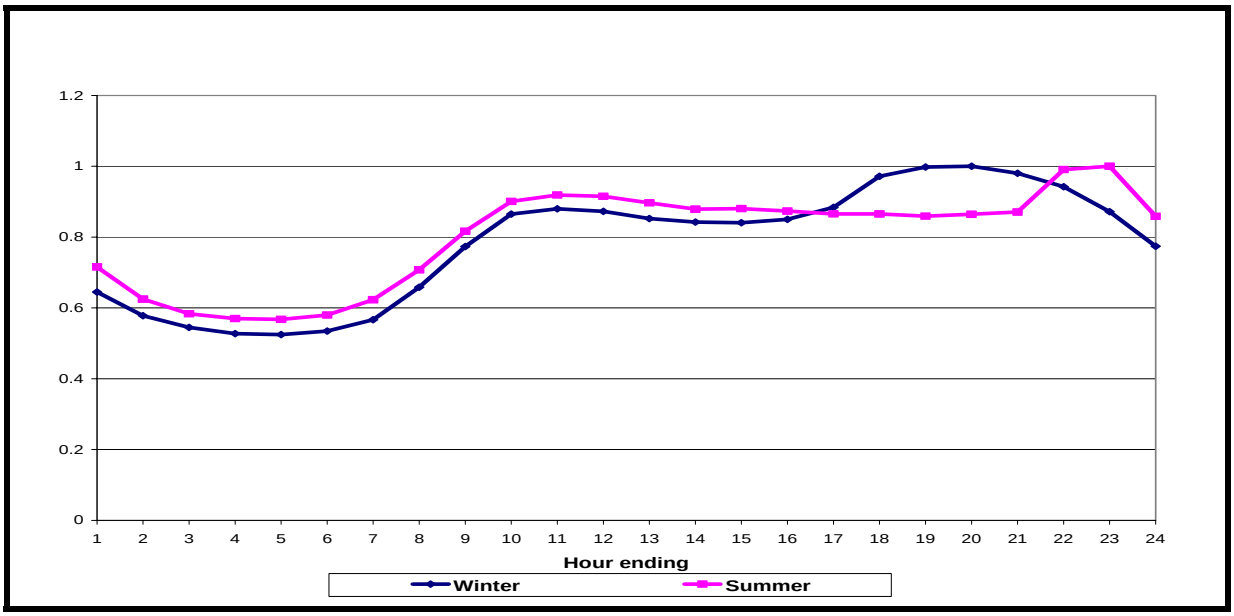
Typical hourly load curves, which were derived from average hourly loads based on actual hourly dispatch data for each month of 2000-2004, were used to analyze the changes in load shapes. The analysis has revealed that no significant shift in consumption pattern has occurred since 2000. Average hourly loads for typical summer and winter days are presented on Figures 5.2 and 5.3.

Figure 5.2 Average Hourly Load Shapes



For easier comparison of load shapes, Figure 5.3 presents the relative load shapes for a typical summer and winter day. Average hourly loads are calculated for each and plotted against hours to develop relative load shape. Average hourly load is defined as hourly load divided by the maximum daily consumption, thus the hourly average load varies between 0 and 1 regardless of the values of maximum load.

Figure 5.3 Relative Load Shapes for Typical Summer and Winter Days



5.1.3 Evaluation of Historical Sales

Figure 5.4 depicts the significant change in the structure of retail sales from 1999 to late-2004. A significant growth has occurred in the residential and commercial sectors.[1] The electric power sale to the industrial sector has also increased, however, the overall sales pattern has been subject to sporadic and high variations.

Figure 5.4 Monthly Electric Power Sales

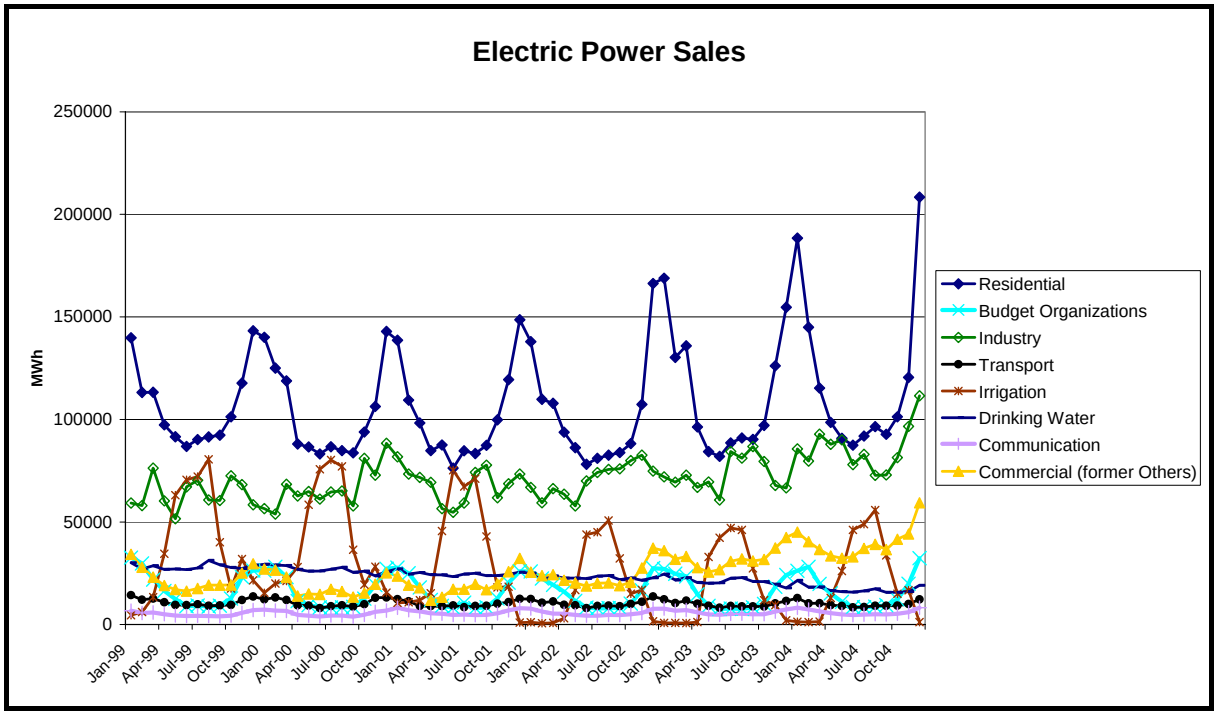
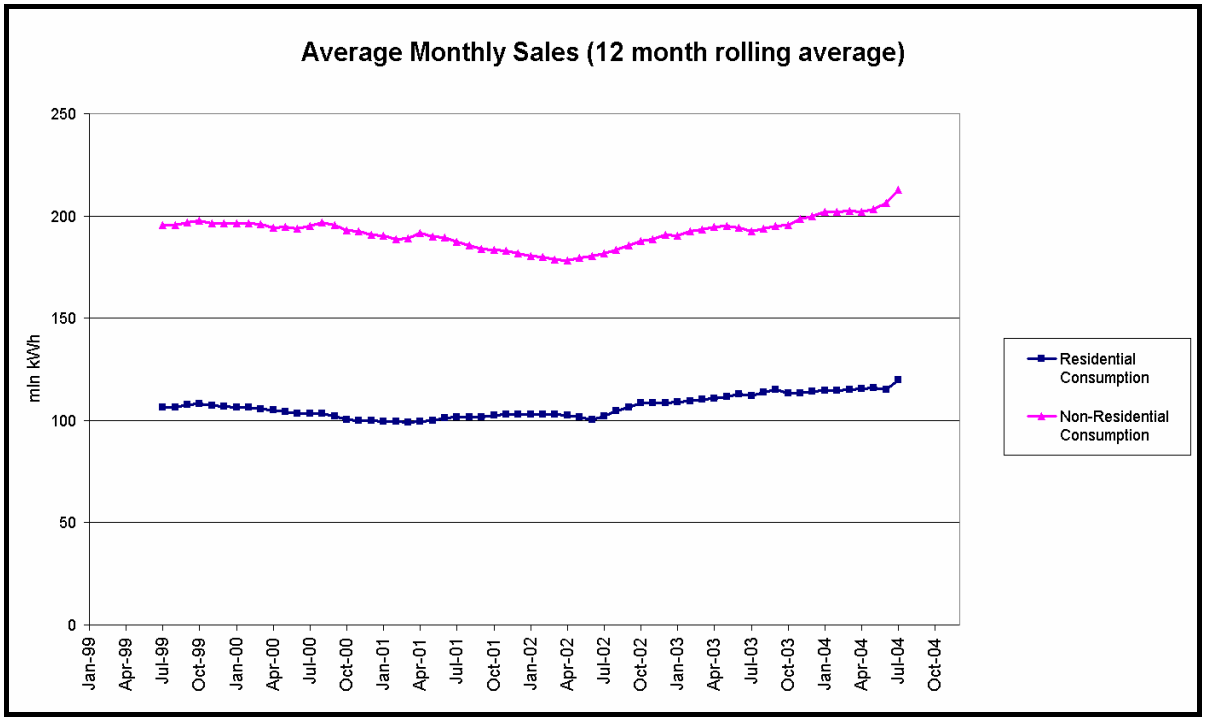


Figure 5.5 provides the sales to residential consumers and compares those sales to the total non-residential sales from 1999 to 2004 using 12 month rolling averages. Use of rolling averages allows elimination of variations caused by differences in whether conditions and can help to identify and illustrate long-term trends. Figure 5.5 was developed based on distribution company's monthly sales data.

January 1999 to December 2004 can be divided into two distinctively different power sales period, a period of declining sales, which lasted until April – July 2002, followed by a period of growth in sales. Since 1999, the overall growth in the residential sector has been about 6% for the residential sector and about 5% for non-residential; clearly indicating the predominant role of the residential sector in Armenia's electric power sales growth.

[1] Though there is no such category as commercial sector in the statistics currently maintained in ElNetArm, its original customer categories were regrouped to single out this customer category.

Figure 5.5 Residential Sales vs. Non-Residential Retail Sales



5.2 DEMAND-SIDE MANAGEMENT

5.2.1 Background & Situational Analysis

Demand Side Management (DSM) include programs that are designed and implemented by the electric energy companies in order to minimize capital expenditures for expansion projects while meeting future load growth. DSM programs are normally financed through the tariffs. Other energy efficiency or conservation programs may occur outside of the utility programs and are usually designed and implemented by Energy Service Companies (ESCo's) or by the customers. In this chapter, only utility DSM programs and customer sponsored projects with the potential of reducing electricity demand are discussed.

Normally, the LCGP process consider possible DSM programs as an option to help meet future load growth. However, due to excess capacity in Armenia there is very little interest in DMS programs. Projects that may have impact on load growth are being implemented by self generators (e.g., Hatsavan and Lermontov microhydo projets and Max Group and Black Ox farm bio-gasification projects) to protect the environment and/or to reduce dependence on national grid and imported fuel. Currently, bio-gasification projects are not designed to generate electricity but to produce gas as a heat source and replacement of electrical heaters with gas heaters. Furthermore, re-gasification of Armenia and improved access to gas can reduce demand for electricity by replacing electricity with gas for heating purposes. The current operating gas distribution network has 9,608 kilometer of pipe and the gas transmission network is 1,800 kilometer.

The overall impact of the power generated by the self generators is not expected to be significant. The implementation of the wholesale electricity market is also expected to optimize costs in the long-term while maintaining and improving the reliability of the

system. Thus, the potential for the development of DSM programs for economic reasons are not significant and are not considered in the 2005 LCPG analysis.

As reported in previous reviews/plans, the physical plant infrastructure of the energy supply and distribution systems continues to deteriorate due to lack of capital investment and proper maintenance. However, significant improvements in management, implementation of new systems, and reduction in commercial losses have been achieved.

A. *Electricity Sector* - The electricity sector continues to experience deterioration in its generating facilities due to lack of proper maintenance and investment, resulting in the loss of efficiencies. In the transmission sector, the rehabilitation of the 220 kV substations, funded by World Bank, was completed in 2005 and the rehabilitation of 110 kV substations funded by JBIC should commence in 2006. The metering and data acquisition system, funded by USAID continues to benefit the sector and has provided the mechanism for accurate and timely metering of sales/purchases, and proper settlement in the electric sector. Furthermore, the transmission and distribution system technical and commercial losses are reduced substantially, from 50% in 2002 to about 16% in 2004. There are efforts under way to develop micro and small renewable resources, primarily hydro- and wind power facilities within the next five years. A number of micro and small hydro projects are planned or under construction**,** one large hydropower project has been planed, a small (2.6 MW) wind power project was completed in December 2005, and a 20 MW wind farm is proposed. Additional projects are planned for 2010 to 2025.

B. *Natural Gas* - The natural gas supplies to most of Armenia were cut following the collapse of the Soviet Union. Unfortunately, the pipelines were not maintained in the interim period (e.g., cathodic protection was interrupted) and therefore deteriorated significantly. The supply to some consumers was restored (industrial, commercial, and residential) and rehabilitation of gas transmission and distribution lines began in late 2003. Currently about 400,000 consumers have been connected to the system and it is projected that by the end of 2006, gas supply would be available to 580,000 consumers across the country, which is more than the number of consumers with access to gas service during the Soviet era. Also, construction of Iran-Armenia pipeline is expected to be completed in 2006-2007 timeframe, improving the gas supply reliability for the consumers.

C. *Thermal energy supply* – The district heating systems have deteriorated due to lack of maintenance. Only a few of the district heating systems in the country are currently operational. Estimates of the delivered efficiency of the district heating systems are as low as 20%, and collections are low. As a result, most consumers now use electricity, natural gas, kerosene, and/or wood-burning stoves for heating. Armenia's heating strategy was approved and is being implemented, which provides financing for economically sound heating projects. Recently, a number of energy efficiency demonstration projects on boiler houses and heat supply systems in residential, municipal-government, industrial, and agricultural sectors were implemented. Two biogas facilities were also constructed to meet some of the electrical heating needs at two cattle farms. The economic viability of these demonstration projects still needs to be validated. However if successful, these projects and their potential replication may replace some of the electric heating load, particularly for space-heating, in Armenia's agricultural sector.

5.2.2 DSM Impacts

It is not expected that DSM will have a significant impact on the energy demand in the near future. However, several pilot projects have been completed and other efforts are underway to study the energy situation and provide data for use by energy planners, consumers and the GoA.

USAID has been sponsoring and continue to sponsor many demonstration projects that can be considered as DSM type projects. These projects have focused on:

- Improving the efficiency of small heating systems for one or two apartment buildings;
- Improving the energy efficiency of electric use and heating supply systems for municipal and government owned facilities;
- Installing more efficient industrial processes and equipment at selected commercial and industrial facilities;
- Utilization of animal waste for biogas production and generation of heat at agricultural facilities.

The estimated annual electrical savings of about 18 recently implemented projects is about 6,655 MWh. The results of these projects, together with the GoA's energy strategy should provide data for analyzing the future potential in slowing down the growth in electrical demand.

Relative to other countries of the Newly Independent States, Armenia is better suited for the promotion of energy efficiency because the state of privatization/commercialization in the power sector is such that most consumers pay in full for the energy services they use. Since 2002, commercial losses are substantially reduced. This level of commercialization has two impacts. First, decrease in demand by consumers due to better management of the system and reduction of commercial losses (only 40% of the commercial losses have been converted into actual sales, hence, resulting in reduction in demand equal to 60% of the commercial losses). Second, with consumers paying for the energy they use, consumers can benefit from the economic savings that result from energy efficiency so there is an economic incentive for them to implement efficiency measures that reduces their electricity usage. Obviously, if consumers are not paying for their energy use, then there is no economic incentive for them to implement efficiency measures. Also, Armenia is better suited to promote energy efficiency since the existence of the PSRC provides an opportunity for the agency to serve as a focal point for helping to promote energy efficiency through such means as standards of performance for the utilities, consumer information/education and/or tariff design.

The implementation of a number of other energy technologies including solar heat water systems, ground source geothermal heat pumps, and anaerobic digestion systems (for the conversion of agricultural waste to biogas and electricity) could further reduce electricity demand growth if there are incentives for their implementation. These incentives may be established by developing a tariff structure that encourages energy efficiency and new energy efficiency standards for new building construction in the case of solar heat water systems and ground source geothermal heat pumps. Anaerobic conversion of animal waste to biogas for the production of heat appears to be gaining some popularity in Armenia due to its environmental benefits as well as its potential for reducing energy consumption at cattle and poultry farms. The economic benefits of the anaerobic digestion system could be further improved by generating combined heat and electricity. However, installing gas engines or micro turbines could complicate the system operation,

would require personnel training for operation and maintenance of the turbine or engine; and would necessitate inventory of equipment and parts that are not currently easily accessible in Armenia.

Solar, geothermal, and anaerobic systems can also contribute to the environmental health of Armenia either by not generating any emissions or by eliminating emission of methane from animal waste ponds and discharge of untreated waste water to the waterways. Furthermore, they can also reduce emissions of CO_2, NO_x, and SO_x by displacing natural gas fired generation. These systems are described in detail in Appendix B.

5.2.3 DSM Potential

DSM programs, most likely, will not be developed and implemented on a wide-spread basis in the foreseeable future although they have the potential to reduce the peak load in Armenia.

Many of the solar energy projects demonstrated in Armenia by the donor agencies are no longer in operation primarily due to cost of replacement parts. Also, low electricity Tariff (AMD 22/ kWh currently about 5 US Cents/kWh) does not provide economic incentives or justification for broad base energy efficiency activities/projects.

5.2.4 DSM Recommendations

It is recommended that an Integrated Resource Planning (IPP) Process be implemented in the future. Such a process will incorporate both supply-side and demand-side resources options into the future resource mix of the country. However, before this process can be implemented (1) a database of needed information must be developed and maintained and (2) expert personnel must be trained for carrying out the necessary tasks.

- Database development

  In order to develop a more meaningful energy resource plan, it is necessary to begin to develop and maintain databases of information that provide important inputs to the models. While this report addresses least cost planning, the databases mentioned here can also provide valuable information for many other needed energy sector data, such as rates, customer information programs, energy efficiency programs and others.

  Some of these databases are described below:

a. Economic Factors – A database of many economic factors that influence energy decisions should be developed and maintained. Likely, there is abundance of information already available, but not in a single database. A single computerized database system should be developed that can be accessed by energy planners and DSM program designers.
b. Load profile database – Currently, there is no database at the customer level on hourly load shapes. It would require extensive resources, both from a human resource and an hardware viewpoint, and the time to develop these databases. A database should be developed using traditional and customized load research methods. The load profile data has many important uses in addition to that of resource planning, including rates, cost of service studies, customer information programs, distribution system planning and inputs into technical specifications for distribution systems. The load profile database should be analyzed and reported in several different ways, including:
    i. Levels – system, substation, customer and end-use

ii. Seasonal (average days)

iii. System Peak day

c. Customer data – Data on customers is extremely important, not only for system planning purposes, but for many other reasons, such as customer information programs, DSM program planning, energy efficiency planning and for regulatory purposes. Extensive effort is required to provide accurate and reliable customer data. At a minimum, the customer data should include:

i. Energy use (kWh, m^3 of natural gas/propane)

ii. Monthly energy bills

iii. Demographics

iv. Income levels of households

v. Appliance saturation

vi. Customer preferences (i.e. electricity, natural gas, steam, etc.)

vii. On-site energy resources/generation

The customer database should be designed so that trends can be charted and reported to provide important input into the forecasting models.

d. Equipment/Appliance efficiencies – A database on equipment (i.e. motors, HVAC, etc.) and appliance (i.e. refrigerators, stoves, etc.) efficiencies is needed, not only for existing stocks, but also for future new technologies. Together with the information from the customer database, this information can be incorporated into the forecasting model to determine the possible impacts from improvements in energy efficiency and the replacement rates of equipment and appliances.

e. Equipment/Appliance availability – The availability of new energy efficient equipment and appliances plays a big part in determining the replacement rates. A database of suppliers and the types of equipment and appliances available to the consumers is also needed.

- Training of personnel

Training of experts in several areas is needed in order to provide high levels of experienced individuals to carry out the tasks. Some of the training that is needed in the near future includes the following:

a. IRP and LCP modeling – New models will require training for the users and computer programmers, who may customize the models to meet Armenia's needs., The modeling expertise should be institutionalized at the Energy Institute and PSRC, and skills training provided as needed.

b. Forecasting – New forecasting models may require training in econometric and statistical techniques that are incorporated within the computer models.

c. Load Research – Armenia has no load research data, therefore, training in all aspects of load research is needed, including sampling techniques, data analysis, and load profile metering and reporting.

d. Customer Research – Additional training will be needed for developing a customer research group that has the expertise in planning and conducting surveys, analyzing the results, maintaining accurate and reliable databases and reporting the results.

5.3 FORECAST OF ENERGY AND REQUIRED GENERATING CAPABILITY

The assumption used in the 2005 LCGP is that Armenia's system should be able to operate independent of the neighboring countries although there are good reasons for Armenia and Iran to continue electricity banking/exchange. The high interconnection capacity, different peaking seasons, and supporting each others' system (i.e., operate in parallel except when stability concerns requires disconnection of the two systems) would benefit the consumers of both countries. With the assumption of an independent system throughout the study period, previously conducted reserve studies, and the aging generating units, 30% required capacity margin was assumed for the study (30% was used for IAEA study and 25% was used in previous LCPs).

The comparison of dependable generation capacity of the generating units in Armenia for various demand forecasts and reserve margin scenarios are depicted in Figures 5.6 to 5.9.

Figure 5.6 ANPP retirement by 2016; Low growth peak forecast

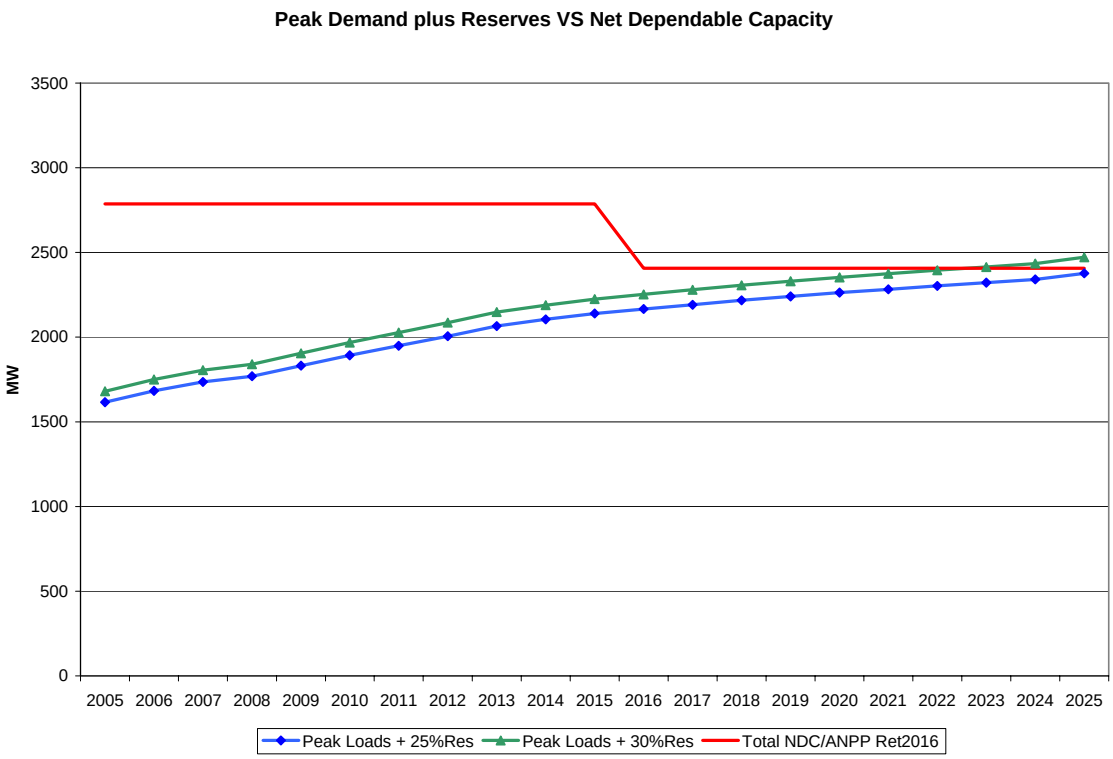


Figure 5.6 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2015, the demand will grow at a low growth rate and no new replacement capacity is added. Given the assumptions, in this scenario Armenia does not need any additional capacity to meet required system capacity throughout the forecast period with 25% reserve requirement. For the 30% reserve scenario an additional 70MW of capacity would be needed by 2025.

Figure 5.7 ANPP retirement by 2016; Reference case peak forecast

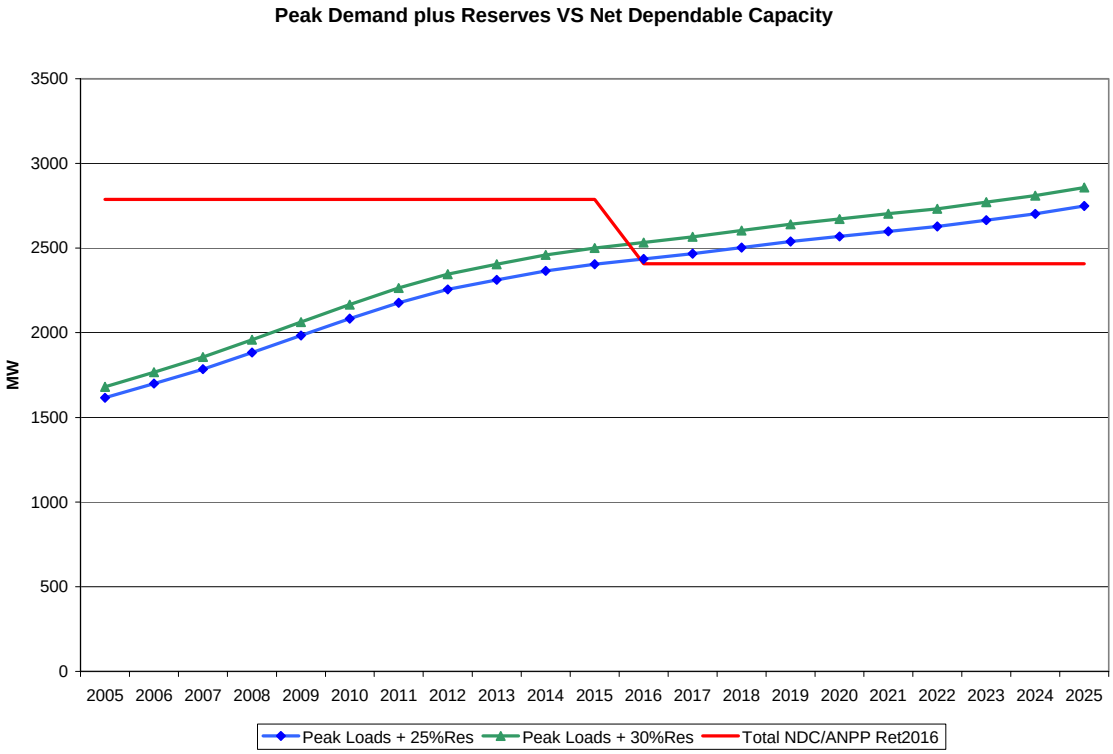


Figure 5.7 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2015, the loads will grow at the most probable forecast and no new replacement capacity is added. From this standpoint, Armenia would need additional 100 MW of capacity by 2015 and 450 MW by 2025 to meet system requirements.

Figure 5.8 ANPP retirement by 2016; High growth peak forecast

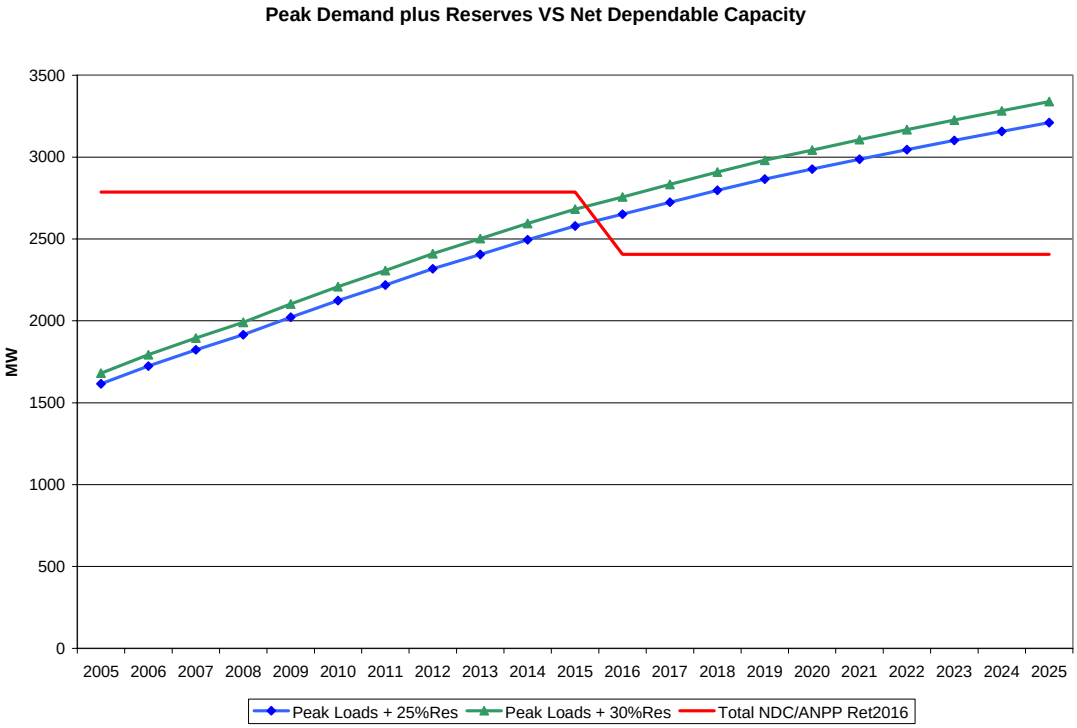


Figure 5.8 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2015, the loads will grow at the high forecast level and no new replacement capacity is added. For this scenario, Armenia would need 360 MW to 940 MW of capacity between 2015 and 2025 respectively.

Figure 5.9 ANPP retirement by 2016 and TPPs are retired by 2020; Low growth peak forecast

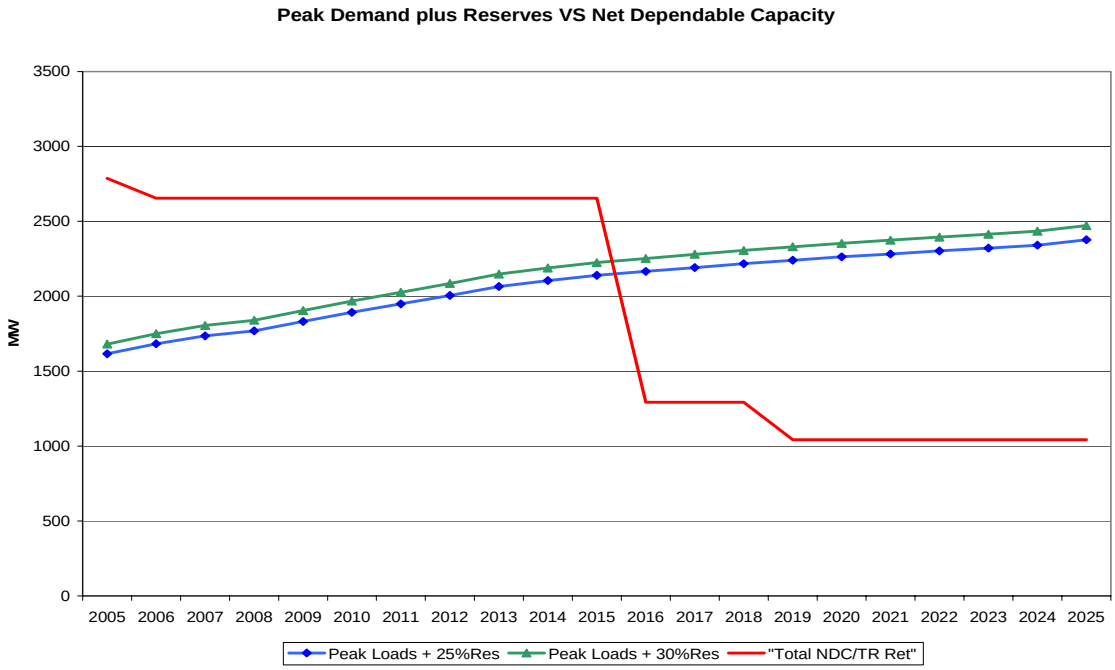


Figure 5.9 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2015, and old TPPs are retired by 2020, and the loads will grow at the low forecast level and no new replacement capacity is added. For this scenario, Armenia would need 960 MW to 1430 MW of capacity between 2015 and 2025 respectively.

The economics of adding new capacity before the retirement of the ANPP in order to reduce overall power costs was evaluated in the IPM dispatch and economic analysis. The evaluation of the energy savings versus operating costs of new generation is discussed in Chapter 7.

6. SUPPLY-SIDE ANALYSIS

6.1 EXISTING SUPPLY-SIDE RESOURCES

6.1.1 Life Extension Expenses and Capital Additions

Most plants in the power sector have exceeded forty years of operation and are operating beyond their design life. An exception is ANPP which will reach its design life in 2015. As the electric load has decreased over the past decade, the thermal-power plants have seen less and less energy output. With forecasted electric load increase in the future, the operating hours of the thermal units may be somewhat higher, depending on the amount of hydro generation. Regardless of the hours of operations, some of the units are needed as back-up for the system during low demand periods, when ANPP is offline for maintenance, and to generate occasionally during the months of higher loads (winter) until construction of new and more efficient units are justified. The cost to maintain these generating units for this type of service is low. However, given the inefficiency of the units and the projected gas price, it could be costly to operate these units for extended period of time.

Costs of new plants; plant improvements, decommissioning, or life extension; and operation and maintenance (O & M) expenses were forecasted based on previous reports for Armenia and for similar projects in other countries in the region, evaluation of nuclear options, previous least cost plans, and other publicly available sources. Currently, it is not clear if sufficient funds will be available for ANPP's capital improvements and/or O&M costs, including safety improvement costs or the decommissioning of the plant by 2016. There is also concern about availability of sufficient funds for capital improvements of selected hydro and thermal units.

Table 6.1 below provides the capital and operation and maintenance (O&M) costs for different type technology/plants (existing and new units). The safety upgrade costs for ANPP are included in its annual O&M costs.

6.1.2 Dependable Capacity

The 2006 LCGP uses the gross generation of the plants for determining total system capacity available to meet system capacity requirements (peak plus reserve margin).

Monthly dependable capacity for hydro power plants (Cascades and small hydro-electric plants) is based on monthly average peak load production based on normal annual precipitation. The net dependable capacity of hydro-electric plants (Cascades plus the small hydro plants) for the month of January (2004) was used to determine the total net dependable capacity available during system peak season to meet the system requirements.

Table 6.1 Capital, O&M and Other costs (2005 $)

Technology & Features	Gas Fired					Nuclear			Hydro Power Plant			
	Existing	Gas Fired Combined Cycle Plant			Simple Cycle	ANPP		New	Existing	Shnokh	Megri	Lori-Berd
		New	Refurbishing Hrazdan # 5	Yerevan TPP		Decom. by 2016	Life Ext. to 2036					
Gross Capacity, (MW)	1610	400	440	225	75	440	440	2*728 - 1154		70	140	68
Net Heat Rate, (Btu/Kwh)	10306 – 10384	6075	8333	6390	9220	11374	11374	9830 - 11078		N/A	N/A	N/A
Construction, (years)	N/A	2.5	1.5	2.5	2	5	5	5 - 7		5	5	5
Capital Cost, ($/kW)	N/A	600	320	635	468	120	682	1376 - 1864		1858	1000	1606
Decommissioning Cost, ($Million)	N/A	N/A	N/A	N/A	N/A	285*	285*	$214 – 447*	N/A	N/A	N/A	N/A
O&M Cost:												
Fixed ($/kW/yr)	5.77 - 6.02	14.0	14.0	15.04	10.5	137.5	75.0	36.1 – 70.7		11.4	13.9	13.9
Variable ($/MWh)	0.24 – 0.53	0.87	0.87	0.96	0.8	0.35	0.35	0.00-0.4				
Fuel Price ($/MMBtu)	4.58	4.58	4.58	4.58	4.58	0.53	0.53	0.164 - 0.513		N/A	N/A	N/A
Plant Life, (year)	30	30	30	30	30	10	30	50 - 60	40	40	40	40

* Decommissioning costs are considered as fixed annual O&M costs.

6.2 FUELS ANALYSIS AND FORECAST

The nuclear fuel costs are assumed to increase at 3% per year for the next 20 years, details of the forecast is provided in Appendix A. The natural gas prices were forecasted for the entire study period. Details of the fuel price forecasts can be found in Appendix E.

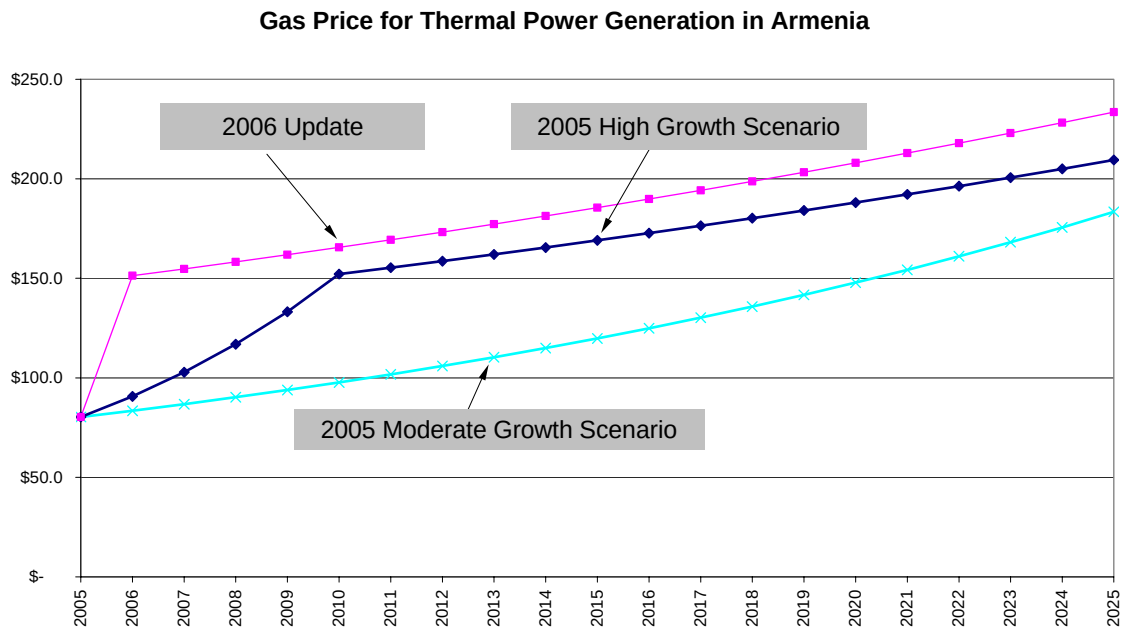
The price of natural gas is a major factor in determining generation cost and represents the single largest cost item included in retail electric rates. The significant uncertainty associated with the natural gas prices is due to unstable world oil prices and political factors. The 2005 LCGP assumed a low/moderate (annual average price increase of about 4.88% at the border and 4.22% at the power plants) and a high (5.63% at the border and 4.91% at the plants) natural gas prices increase scenarios for Armenia based on projected fuel prices at the western boarder of Russia and taking into account the unique market conditions of Armenia.

Since the uncertainties related to Russia's "political gas price" is no longer an issue, only one scenario of fuel price increase, 2.37% per year at the power plants, was used for LCGP 2006. The lower average price increase is attributed to higher starting price ($110 per tcm) in 2006.

While, Iran-Armenia gas pipeline may provide some level of competition for gas supply to Armenia, it is unlikely that the price of gas from Iran would be significantly lower than the price of gas from Russia.

Figure 6.1 provides the forecast of generators natural gas prices for 2005 through 2025, for low/moderate and high price growth scenarios.

Figure 6.1 Natural Gas Price Forecast for Power Generation in Armenia



6.3 GENERATING UNIT SIZING

In determining the unit size, a unit size should be selected so that in case of a failure of a unit, the electric system can continue operation without putting the entire system at risk. The dispatchers like to have many smaller units available to them, rather than a few large units. The norm used for sizing a new generating unit is about 10% of the system peak load." However, this norm can be exceeded if the system is tied to other systems in parallel operation and with appropriate transmission capacity. For example, Armenia, with projected peak load of about 2,600 MW in 2025, could plan for a unit with a gross capacity of about 300 MW. However, given Armenia's Vorotan HPP capabilities, parallel operation and transmission capacity with Iran, and the potential for parallel operation with the other neighboring countries, Armenia could select larger unit(s).

Sizing of the units should not be taken lightly, since mishaps/failures of a large unit can bring the entire system down. The reasons for not selecting very large units without appropriate justifications are:

1) Inability to cover spinning reserve and/or the high cost of providing spinning reserve to cover the first contingency of the power system, i.e., the sudden loss of a large generating unit out of dispatch;
2) The risks, both financial and the security of the country, related to a pre-mature retirement or an extraordinarily long outage of a large generating unit.
3) The rate impacts caused by the inclusion of a large generating unit into rate base when the unit is commissioned;
4) The rate impacts caused by the inclusion of replacement power (either expensed purchased power or large investment for new units) when the unit is retired.

The Armenian power sector has operated a 440 MW unit (ANPP), about 40% of the system peak load, since 1995 with remarkable safety record and system reliability. Therefore, it can be argued that Armenia could select a unit of approximately 1200 MW if its system peak load is expected to be 2600 MW. However, the technical and financial issues related to such a selection should be extensively examined and justified before a unit size is determined.

6.3.1 Spinning Reserve Impacts

The standards for spinning reserve require that the system must be able to recover fully from largest possible outage condition (the so-called first contingency or N-1 occurrence) without any loss of supply to any firm retail consumers. When a large generating unit is operating at full load, the system must be dispatched so that the other units are backed down to lower levels in order to create enough replacement energy in case of a sudden outage by a large unit. In many instances, higher cost generators are backed down in order to obtain the spinning reserve, thus increasing the cost of dispatch. Also, if the size of a unit is large, there is a strong possibility that the system can not provide enough spinning reserve, thereby creating a potential situation that the standards are violated (firm customers are disconnected) when a large unit suddenly goes off-line. Both these conditions are actually worse when the system load demand is low (off peak seasons and at night) and a lower number of generating units are on-line, therefore, unavailable to provide spinning reserve.

6.3.2 Exposure to Outages or Pre-Mature Retirement

Planners perform “what if” scenario analysis to examine the risks to consumers of certain future events. Two events related to large generating units that create a risk for consumers are:

1. Pre-mature retirement of the generating unit; or,
2. Unplanned long-term maintenance outages.

These events can have adverse effects on the system power costs (retail rates) and the reliability of the system (supply of power to consumers). Although any low energy cost generating unit can create such risks, operating smaller generating units mitigates these exposures. If the generating unit sizes are small, the risks of pre-mature shout-down is distributed among a number of units and the impacts of unscheduled or pre-mature shut-down of a small unit on the consumers are reduced. Contingency plans must be in place to take care of the above mentioned possible events.

6.3.3 Rate Impacts after Commissioning

Introducing a large new unit will increase retail tariffs for electric consumers due to the recovery of investments (depreciation and return on assets). The system requirements for new capacity may in fact be small, but adding the cost of investment recovery into rates may put a heavy burden (rate shock) on consumers to pay for all of the capacity even though the total capacity of the generating unit would not be needed for many years into the future. On the other hand, a new technology or unit fuel type may lower energy costs due to lower heat rates or fuel cost (gas vs. nuclear or hydro).

6.3.4 Rate Impacts to Replace the Power after Retirement

In the same light as introducing a large unit pre-maturely, the retirement of a single unit will cause a huge short fall to be covered, especially a unit that provides low-cost energy and is fully depreciated (ANPP #2). Depending upon the system reserve, the unit retirement may require some replacement capacity and certainly replacement energy. In this case, the consumer will feel a rate shock when the old unit is retired and the costs for replacement energy and capacity are placed into retail rates. Therefore it is essential that retirement of ANPP by 2016 is planned appropriately, and the end use tariffs are adjusted gradually to prevent the need for sudden increase in tariffs due to retirement and replacement of the ANPP.

6.4 SITE ANALYSIS FOR FUTURE RESOURCES

As described earlier, new resources must be evaluated both for their direct costs and for indirect cost factors. The indirect cost factors include environmental impacts (land, air, and water), access to fuel transportation systems and access to the electric networks. A database on this information has been created by MoE and work continues on obtaining all the information needed for the above factors. Once the data gathering is complete, the use of these factors in determining the viability of new resource technologies can be used along with the direct cost factors.

6.5 NEW SUPPLY TECHNOLOGIES

In addition to gas turbine and combined cycle gas unit, other new supply technologies were reviewed and analyzed to determine if they should be included in the list of viable

potential technologies for Armenia. These technologies are described in the following sections.

6.5.1 Nuclear Options

Relying on a single large unit to supply a large portion of Armenia's electric sector has a number of system reliability and energy security issues that should be carefully examined. Assuming that safety improvement projects that have been identified for ANPP are implemented properly and on a timely manner, and it is determined that the ANPP will retire in 2016, two nuclear options can be considered for Armenia. First, life extension of ANPP's unit #2 through 2035, and second, replace ANPP with a new unit(s), either at the same site or at a new site. In the case of new nuclear option, several designs are available today that could be constructed in the near future (by 2015 – 2020). These design options as well as their pros and cons are presented below and are also provided in detail in Appendix A.

CANDU 6

The CANDU 6 is designed by Atomic Energy of Canada Limited (AECL). CANDU stands for "CANada Deuterium Uranium". CANDU is a Pressurized Heavy Water Reactor (PHWR) that uses heavy water (deuterium oxide) for moderator and coolant, and natural uranium for fuel.

The CANDU 6 is designed with a net generation capacity of 674 MW. CANDU 6 units are typically built in sets of two to provide a plant with generating capacity of 1348 MW. Ten CANDU 6 reactors are currently in operation in Canada, Korea, Argentina, China, and Romania.[2] An additional unit is under construction in Romania. The CANDU 6 design has been licensed by the Canadian regulatory authority as well as the regulators in the other countries where they are operating.

The CANDU plants have a number of unique features that would be beneficial in a situation like Armenia:

- Use of natural uranium widens the source of supply and makes fuel fabrication easier. There is no need for uranium enrichment facility.
- A two unit plant provides more flexibility and reliability for a small grid such as in Armenia. If one unit goes offline, the other unit could supply most of the domestic energy demand.
- CANDU design uses pressure tubes rather than a large pressure vessel to hold the fuel, which allows on power refueling, resulting in potentially higher capacity factors. The top performing CANDU 6 units have achieved capacity factors in excess of 96 percent.
- The use of a pressure tube reactor eliminates the need for a large reactor vessel, which will be difficult to transport into Armenia.

There are two primary disadvantages to the CANDU 6 design:

[2] *Next-Generation CANDU Technology*, Technical paper by Jerry Hopwood, Kenneth Hedges and Mark Pakan, Atomic Energy of Canada Limited (AECL), at the ICONE-10 Conference in Arlington, Virginia from April 14-18, 2002.

- The potential for leaks from heavy water systems and the need for makeup supplies of heavy water, which must be obtained periodically or manufactured by special equipment onsite.
- One year reactor outage for replacing the pressure tubes after about 30 years of operation although this may not be a serious problem for a two unit plant.

Some CANDU projects have been completed in about 69 months, from the contract effective date to commercial operation including a 46-month construction period from the time of issuance of the construction permit to fuel loading.

ACR-1000

The Advanced CANDU Reactor (ACR) is an evolution of the CANDU 6 design.[3] The ACR is a pressurized water reactor that uses slightly enriched uranium (SEU) fuel, light water coolant, and smaller amounts of cool, low pressure heavy water as a moderator.

The ACR was initially designed for generating capacity of 700 MW (ACR-700) and intended to be installed in a two unit plant, similar to the CANDU 6. Subsequently, AECL revised the design to produce 1125 MW (ACR 1000) to be more competitive with other nuclear plant designs. A safety certification of the ACR-1000 design by Canadian Nuclear Safety Commissions is currently underway, and certification by the US Nuclear Regulatory Commission (NRC) is planned by 2012. The ACR 1000 is being proposed by AECL for a four unit project in China. Two or more ACR-1000 units are expected to be operating in Canada by 2015.

The evolutionary design of the ACR increases plant efficiency and reduces construction and operating cost as compared to the CANDU 6.[4] The use of SEU fuel, while more expensive, provides a reduced core size and improved safety margins. Using light water as coolant eliminates some systems and greatly reduces the need for make up heavy water. The plant design also incorporates passive safety systems that provide better safety assurance while reducing construction and maintenance costs. The turbine cycle has been improved significantly to provide better thermal efficiency.

A major area of improvement in the ACR design is in the area of construction optimization. The ACR design emphasizes layout for streamlined construction through a highly modularized design. By preparing the complete reactor building design in the form of drop-in modules, the total project schedule—including engineering, procurement, construction and commissioning—can be substantially reduced. This allows a critical path schedule, for a replication unit, of 48 months with construction duration of less than 36 months.

Like the CANDU 6, the ACR plant will require a one year outage for replacement of reactor tubes after about 30 years of operation. In the case of Armenia, where there may not be alternative generation available, a year long outage of a single nuclear unit could present a problem.

AP1000

[3] *The Advanced CANDU Reactor (ACRTM): Ready for the Emerging Market*, Technical paper by Kenneth Hedges, Atomic Energy of Canada Limited (AECL), at ANES 2002 Symposium, October 16-18, 2002.

[4] *AECL and CANDU / ACR-1000 Overview*, presentation by Atomic Energy of Canada Limited (AECL), June 2005.

The AP1000 is a PWR with a 1,117 MW generating capacity. It is essentially a higher power version of Westinghouse's 600 MW design, the AP600, which the NRC certified in 1999.[5] The Westinghouse AP1000 standard plant design received NRC design certification in 2004.

AP is sometimes taken to mean "Advanced Passive". The principal advantage of the AP 1000 as compared to older PWR designs is safety. The safety margins of the AP 1000 are considerably larger and the likelihood of failure much lower because the plant relies on naturally occurring phenomena such as gravity, natural circulation and condensation, guaranteeing a safe shutdown of the plant even in the event of an accident.

The additional benefit of passive design is that passive safety systems are significantly simpler than the traditional PWR safety systems. They do not require a large network of safety support systems needed in typical nuclear plants, such as AC power, HVAC (heating, ventilation & air conditioning), cooling water systems and seismic buildings to house these components. Simplification of plant systems, combined with increased plant operating margins, reduces the actions required by the operator. The AP1000 has 50 percent fewer valves, 83 percent less piping, 87 percent less control cable, 35 percent fewer pumps and 50 percent less seismic building volume than a similarly sized conventional plant.[6] These reductions in equipment and bulk quantities lead to major savings in plant costs and construction schedules.

The plant is designed to be constructed modularly, which will greatly improve construction quality while reducing construction time to about 36 months from the time concrete is first poured until the time that fuel is loaded into the core. This shortened construction period greatly reduces the amount of interest paid during construction period (IDC). Westinghouse projects a 60 month total schedule with 36 months from first concrete to fuel load. [7]

At this time, no AP1000 plants are scheduled for construction. However, the design is being proposed by Westinghouse for a four unit project in China. The AP1000 is included as a reference plant in all of the Construction/Operating License applications being prepared by US utilities.

European Pressurized Reactor

Areva has developed a large (1600 - 1750 MW) European Pressurized Water reactor (EPR), which was confirmed in mid 1995 as the new standard design for France. The French Nuclear Safety Authority (ASN) has issued design approval, which is equivalent to US design certification, for Areva's 1600 MW EPR, the US design certification is planned to begin in 2007.

The first EPR unit is under construction at Olkiluoto in Finland. The second unit is planned for Flamanville in France. The EPR design has been proposed for four new units in China. At least one US Utility, Constellation Energy has included the EPR as a reference plant for their Construction/Operating License application.

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[5] Web sight for Westinghouse AP1000, http://www.ap1000.westinghousenuclear.com/

[6] Marvin Fertel, Nuclear Energy Institute, Testimony for the Record, Energy and Natural Resources Committee of the United States Senate, February 3, 2005

[7] Marvin Fertel, Nuclear Energy Institute, Testimony for the Record, Energy and Natural Resources Committee of the United States Senate, February 3, 2005

The EPR is derived from the French N4 and German Konvoi type designs and is expected to provide power about 10% cheaper than the N4.[8] It will operate flexibly to follow loads, have high fuel burn-up and the highest thermal efficiency of any light water reactor, at 36%. Availability is expected to be 92% over a 60-year service life, obtained through two year refueling cycles, ten day refueling outages, and in-operation maintenance on quadruple redundant safety systems.

VVER 1000

The Russian Joint Stock Company, ATOMSTROYEXPORT, is offering two new designs for VVER 1000 power units. These designs have been developed to meet current IAEA safety requirements.[9] The VVER 1000 model V-428, known as AES-91, nuclear plant has 950 MW net generating capacity. It differs from earlier VVER 1000 designs in that it uses a digital control system designed by Siemens. Two of these plants are being constructed in China and the design was bid for the Finland Olkiluoto project.

The latest version of VVER-1000, the model V-392, is known as AES-92 nuclear power plant and also has a generating capacity of 950MW. In addition to digital controls, the AES-92 has a number of active safety systems similar to those found on a traditional Western PWR. The AES-92 is designed for an 18 month refueling cycle. Two AES-92 units are being constructed in India and two units are planned for construction as Novovoronezh 6 and 7 in Russia. It is believed that ATOMSTROYEXPORT offered the AES-92 design in its bid for the four-unit project in China that was noted earlier.

Advanced Boiling Water Reactor

General Electric Company's (GE) 1300 MW Advanced Boiling Water Reactor (ABWR) nuclear plant was developed in cooperation with the Tokyo Electric Power Company and GE's partners Hitachi and Toshiba. Two ABWR units are in the fourth cycle of successful operation in Japan and two more are under construction in Taiwan.[10] The ABWR received USNRC standard design certification in May 1997. Additionally, an early sight permit application based on the ABWR design has been submitted to the USNRC by a group led by Entergy. The ABWR has received licensing approval in Japan and Taiwan and is currently being reviewed by the European Utility Organization against European regulatory requirements.

If an ABWR were to be built in the U.S., GE estimates, using Taiwan project costs, that the current overnight construction cost would be $1400/kW, with potential for further cost reductions that would reduce the cost to $1200/kW.

The ABWR's operating cycle is 18 months with capability of up to 24 months. The refueling outages duration is 43 days. These outage lengths assume that there is only normal maintenance work and no major turbine generator work. ABWRs have a number of design features that reduce the number and duration of forced outages, major maintenance outages and plant derates. Two major contributors to the improved availability factor are advanced materials and better designed recirculating systems.

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[8] *Lifetime of Nuclear Power Plants and New Designs of Reactors*, French Republic Parliamentary Office For Scientific And Technological Assessment May the 13th, 2003

[9] *Nuclear Power in Russia,* Uranium Information Centre, Briefing Paper # 62 January 2005

[10] *"Evolutionary" Nuclear Plants: Advanced Boiling Water Reactor,* Nuclear Energy Institute, 2005, http://www.nei.org/doc.asp?docid=110.

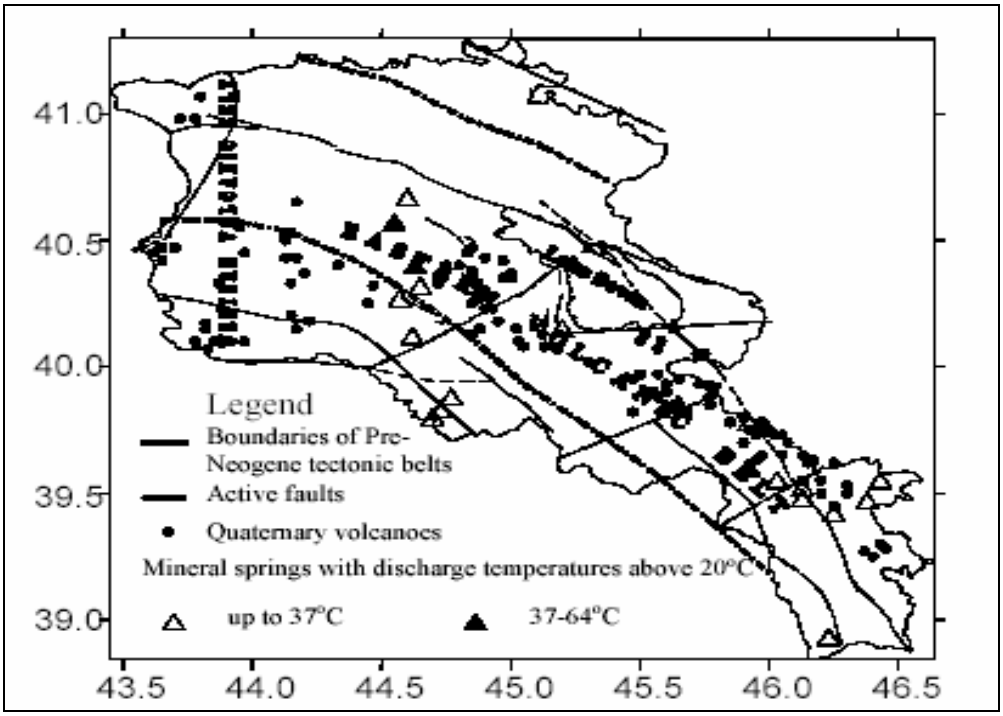
ABWR availability is about 87 percent. The ABWRs in Japan were constructed in only 51 months, as measured from first concrete to commercial operation.

6.5.2 Renewable Resources

Solar Energy – As discussed in the previous section, Armenia has good year around solar potential (yearly average of 4.9 kWh/m2/day). However, widespread utilization of solar energy systems in Armenia is currently prohibitive due to the high costs and lack of availability of equipment, spare parts, and maintenance services. The only exceptions are passive solar and maybe solar domestic hot water systems.

Geothermal Energy - In a study for the U.S. Agency for International Development, GeothermEx reported that although no high-temperature geothermal resources had been identified in Armenia, numerous low-temperature resource areas (cooler than 100 ºC) were present. Figure 6.2 is a simplified tectonic map of Armenia showing the location of springs with potential discharge temperatures of 20°C to 64°C. Results from regional heat flow studies, recent volcanic activity and chemical geothermometer investigations are in good agreement, and lead to a conclusion that an area of geothermal potential in Armenia is the Eastern volcanic belt. Both dry and fluid types of geothermal resources with high enthalpy are available in this area. Also, deep fault zones in most of Armenian territory are promising for hydrothermal resource development.

Figure 6.2 Simplified Tectonic Map Of Armenia



Source: M. Badalyan, "Geothermal Features of Armenia: A Country Profile," Proceeding World Geothermal Congress, 2000.

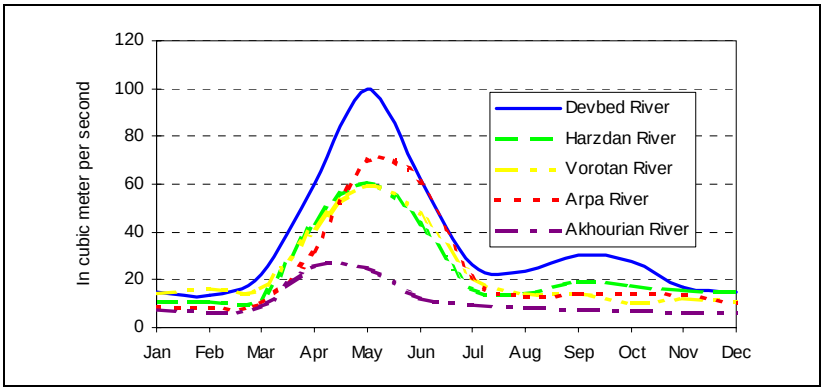
More recent studies[11] and site visits indicate that many of the previously constructed geothermal facilities are in disrepair and are operating at below design capacity. High temperature geothermal sources that may be suited for power generation require deep

[11] United State Agency for International Development, May 26, 1999

wells (over 1000 m). The viability of these resources and their economic sustainability have not been confirmed. More detailed information on geothermal resources in Armenia and geothermal technologies is provided in Appendix B.

Hydro – Armenia has extensive hydro resource, however, over 70% of hydro resources are currently being used or already allocated for use in the near future. Of this amount, over 95% of the resource is used for large scale hydro power generation, 3% for medium, and 2% for small size hydro plants. Of the remaining 30%, about 60% can potentially be used for large to mid size power plants (about 280 MW). The estimated potential for small and micro-hydro generation capacity is about 165 MW. Hydro resources are at their lowest level in winter and summer seasons and at their maximum in mid- to late- spring as shown in Figure 6.3.

Figure 6.3 Water Flow in Major Rivers

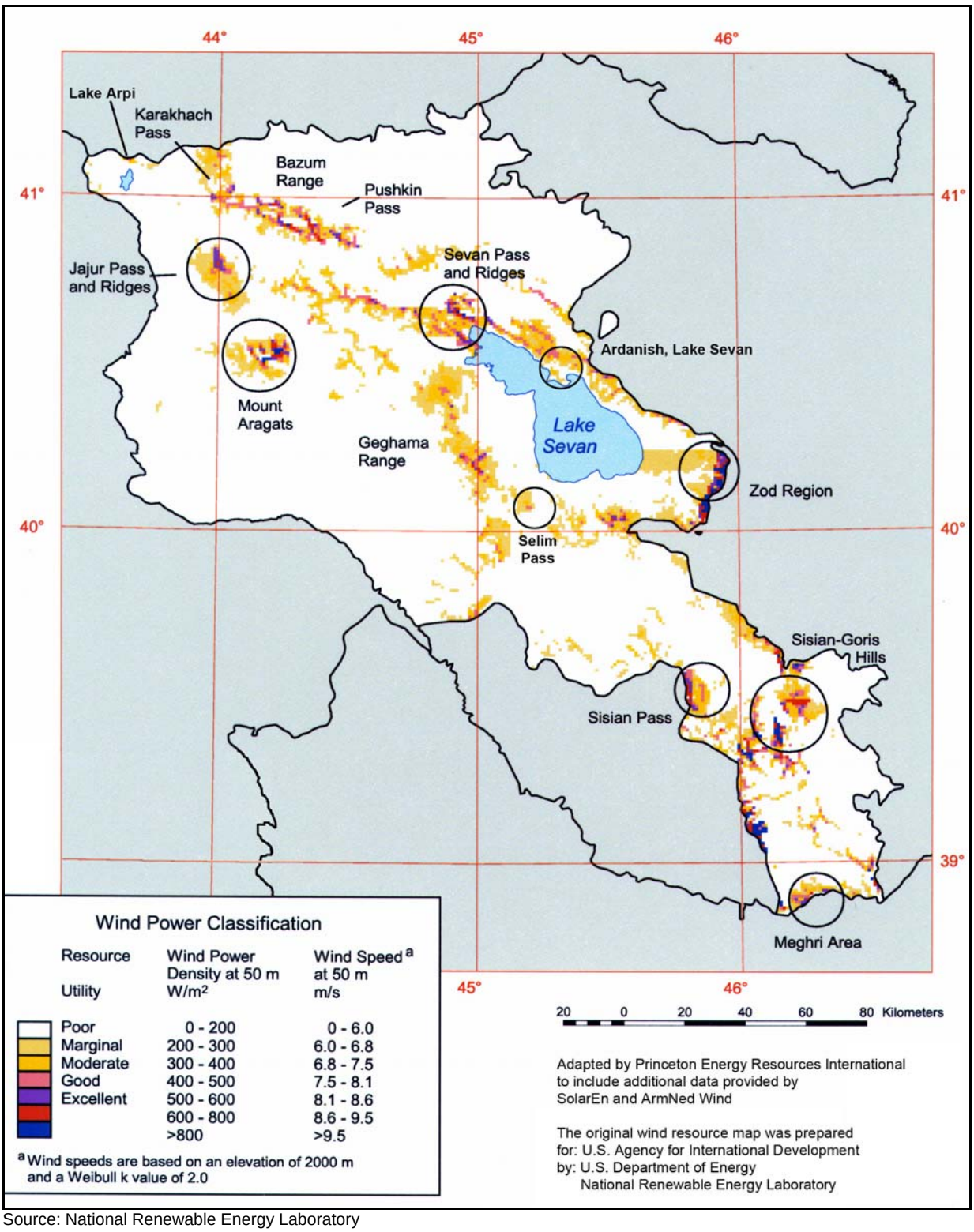


Source: World Bank Technical Paper, "Armenia – Toward Integrated Water Resource Management," November 2001.

Wind - Armenia has excellent wind resources. Studies supported by USAID and the government of Netherlands have shown that Armenia has numerous sites with excellent potential for wind energy development. Figure 6.4 shows the major wind resource areas in Armenia. A recent study completed by NREL for Armenia concludes that the potential for more than 4,000 MW of economic wind power exists in Armenia.

Wind technology has matured from the testing stage into mass production. It is the fastest growing of the utility-scale renewable electric power technologies now in use in many countries. The capacity of a single turbine ranges from 50 kW to 4 MW depending on the turbine design. Currently, a 2.6 MW wind power plant is under construction at Pushkin Pass. This plant uses four 660 kW turbines (47 meter rotor diameter) and has the potential for being expanded to 20 MW. A second wind power plant, for a total capacity of 20 MW, is also proposed to be installed at Zod area. The tariff established by the PSRC for wind power projects is US$0.07 per kWh through 2016.

Figure 6.4 Major Wind Resource Areas in Armenia

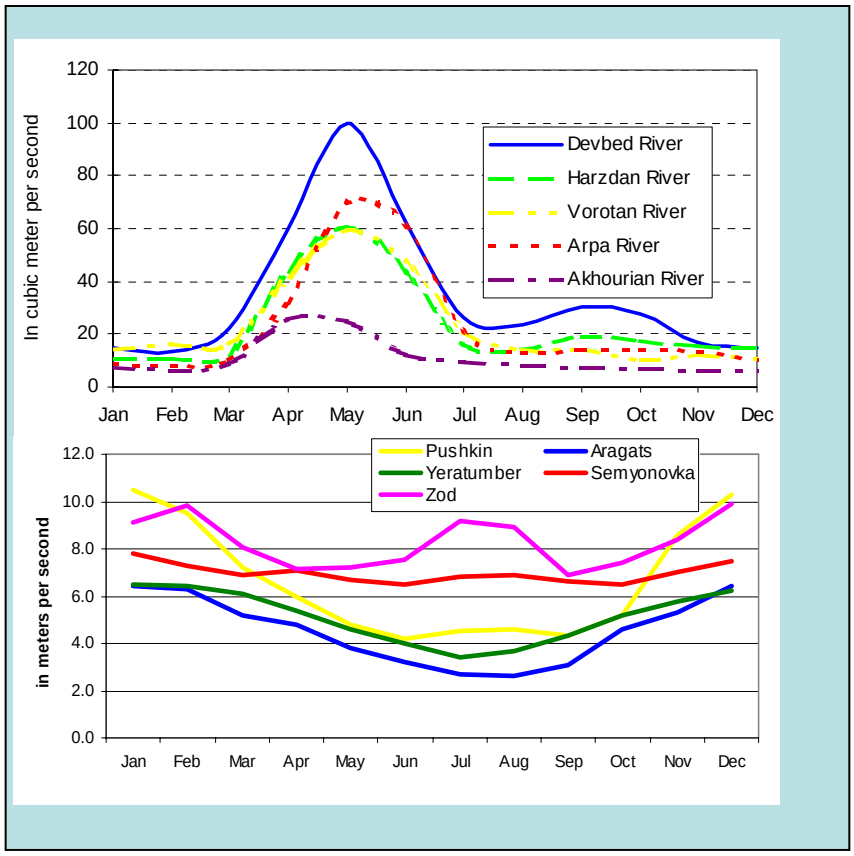


Source: National Renewable Energy Laboratory

Wind data indicates that the winter months are the windiest months in Armenia corresponding to high seasonal demand for electric power and low water resource for hydropower generation. Figure 6.5 compares monthly wind and hydro resources indicating that wind resources could potentially be used to augment the low hydro

resources in the fall and winter. This complementary nature of wind and hydro resources is further discussed in Appendix B.

Figure 6.5 Monthly Comparisons of Wind and Hydro Resources



6.5.3 Fuel Cells

This technology has successfully been demonstrated over the last decade, however the costs are still too high ($2000 - $4000/kW). Units ranging in size from 10 kW to 200 kW are commercially being offered and many 200 kW units are operating worldwide. Carbon-based fuels (primarily natural gas) are fed into the units, with electricity, hot water and very small emissions as output. Car manufacturers are exploring the market for fuel cells driven automobiles “green cars” to reduce smog in large cities. The generating units, with their low emissions levels and very low noise, can be sited practically anywhere, such as inside a city. The technology should be followed to determine the costs and characteristics when the technology is mass-produced.

6.5.4 Clean Coal

Clean-coal technologies continue to improve on costs. However, application of clean coal technology in Armenia is doubtful due to lack of proven high quality coal resources. There are concerns about the fuel quality and the possibility that the coal beds have a saw-tooth shape, making extraction either impossible or economically unfeasible. The clean-coal technologies require tremendous supplies of sorbent/agents for sulfur removal and require disposal of spent sorbent containing fly ash. Coal and sorbent supply and removal of bottom ash (or bed materials plus spent sorbent in the case of some fluidized bed technologies) and fly ash including spent sorbent requires significant rail/road

transportation capabilities. Clean coal technologies are not generally economical unless coal is available domestically and natural gas prices are substantially higher than coal prices on energy equivalent bases.

7. ECONOMIC AND FINANCIAL ANALYSIS

7.1 INTRODUCTION

The 2006 LCGP results are based on scenario analysis. Sixteen cases were selected for further analysis and evaluation. The base case scenario assumed ANPP retirement at the end of 2015, while the alternative case assumed ANPP life extension through 2035. The first 7 cases evaluated the impact of several variables that can potentially have a significant impact on power generation costs. It was also assumed that the proposed 225 MW Yerevan unit will receive soft loans and grants for its construction. The remaining 9 cases were evaluated to assess the impact of certain imposed conditions on the outcome. Case 8 assumes restriction on new nuclear plant construction, Case 9 – restriction on new thermal plants (except JBIC funded 225 MW Yerevan CCGT), Case 10 assesses impact of retiring old thermal plants by 2020, Case 11 assumes that proposed 225 MW Yerevan plant would not receive soft loans and grants, Case 12 evaluates the impact of imposing a reserve margin of 25% rather than 30% on the system, Cases 13 and 14 address the impact of 0% and 1 % demand growth respectively, Case 15 assumes 30 year life for new nuclear projects instead of 50-60 year design life, and Case 16 evaluates the impact of constructing a number of hydro projects as a strategy to diversify fuel sources. The 16 cases with various electricity demands, WACC and other factors are shown in Table7.1. Summary results of the analysis for each case/scenario are presented in Appendix F.

Table 7.1

Studied Cases

No	Case	Demand Forecast			Fuel Price Forecast	WACC Forecast			Special Parameters
		Base	High	Low	New 2006	Base	High	Sensitivity	
1	BNB	X			X	8.48%			
2	BNH	X			X		12.70%		
3	BNS	X			X			14.90%	
4	HNB		X		X	8.48%			
5	HNH		X		X		12.70%		
6	LNB			X	X	8.48%			
7	LNH			X	X		12.70%		
8	No_Nuce	X			X	8.48%			No Nuclear Technology
9	BNB_NT	X			X	8.48%			No New Thermal (exc. JBIC CCGT)
10	TR	X			X	8.48%			Thermal Retirement
11	YC	X			X	8.48%			No JBIC loan
12	25%	X			X	8.48%			25% Reserve Margin
13	D0%	X			X	8.48%			0% Demand growth
14	D1%	X			X	8.48%			1% Demand growth
15	LT	X			X	8.48%			30 years lifetime of new NPP
16	SMP	X			X	8.48%			Strategic Projects

Note: The Case Acronyms (BNB, LNH, etc.) represent the forecasts (Base, High, Low, Sensitivity or New 2006), for Demand, Fuel Price, and WACC

Based on GoA-JBIC agreement, the new 225 MW (gross nameplate capacity) combined cycle at Yerevan TPP was modeled as a given for all cases. However, analysis indicate that although this project is very completive based on JIBC loan conditions (40 years

term, 10 year grace period, 0.75% interest rate), it becomes absolutely noncompetitive when 2006 LCGP financial assumptions are applied for economic analysis.

Also, the Megri HPP financing arrangement, construction schedule, and availability of use for domestic consumption would put this 140 MW unit beyond the planning horizon of this study. Megri HPP's generation, when it becomes available in the next decade, will be exported to Iran to cover the debt associated with its' construction. Therefore, Megri HPP was not analyzed within the scope of the 2006 LCGP.

During the final preparation of 2006 Update, it was confirmed that the natural gas price at Armenia's Northern border would remain unchanged[12] at the level of $110 per thousand cubic meter (tcm) through December 31, 2008. This fact became known after the fuel price forecast was updated, which assumed a uniform growth from 2006 through 2025. According to the assumptions, the price of gas at the border was forecasted to be $112.7 and $115.5 per tcm in 2007 and 2008 respectively. The price differentials of $2.7 and $5.5 are below the level of sensitivity of optimal solution and do not change the outcome or the overall generation strategy.

Furthermore, a very conservative assumption was made regarding the future growth in natural gas price after 2008. It is assumed that by 2025 the price of gas for Armenia would reach 95% of the export gas price at the Western border of Russia and that the growth would be uniform over this period. The latter assumption may substantially underestimate the fuel costs for the thermal power plants. On the other hand, once other non-thermal technologies prove to be economically feasible, under this conservative uniform growth scenario, they would become even more attractive in case of higher growth in gas price forecast..

Other variables that may have a meaningful impact on future generation costs were included in the analysis. These variables included:

- Electric consumption growth (peak load and energy);
- Weighted average cost of capital; and,
- Capacity reserve margin.

Summaries of the analysis for the base case and the sensitivity analysis of varying factors such as demand, WACC as well as analysis of impact from different combinations of these factors are provided in the following sections.

[12] The constant gas price through the end of 2008 is one of the conditions of Hrazdan unit # 5 transfer to the Russian owner.

7.2 BASE CASE/ REFERENCE CASE

7.2.1 Capacity Additions and Changes by Plant Type

The reference case (Case 1 or BNB) was developed assuming most probable electric demand, fuel cost, weighted average cost of capital (WACC), and capacity reserve margin.

Table 7.2 provides the changes in generation capacity for the base case. The optimal solution proposed by the IPM model includes construction of a new nuclear unit (ACR 1000) and replacement of existing obsolete thermal generation with new technologies.

Table 7.2 Gross Generation Capacity Additions and Retirements for the Base Case

Case	Year	2008	2009	2016
BNB	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP 2016

7.2.2 Generation and Capacity Mix

The base case annual generation supply mix, energy and capacity, for the study period are presented in Figures 7.1 and 7.2.

Figure 7.1 Energy Supply by Fuel Type for the Base Case

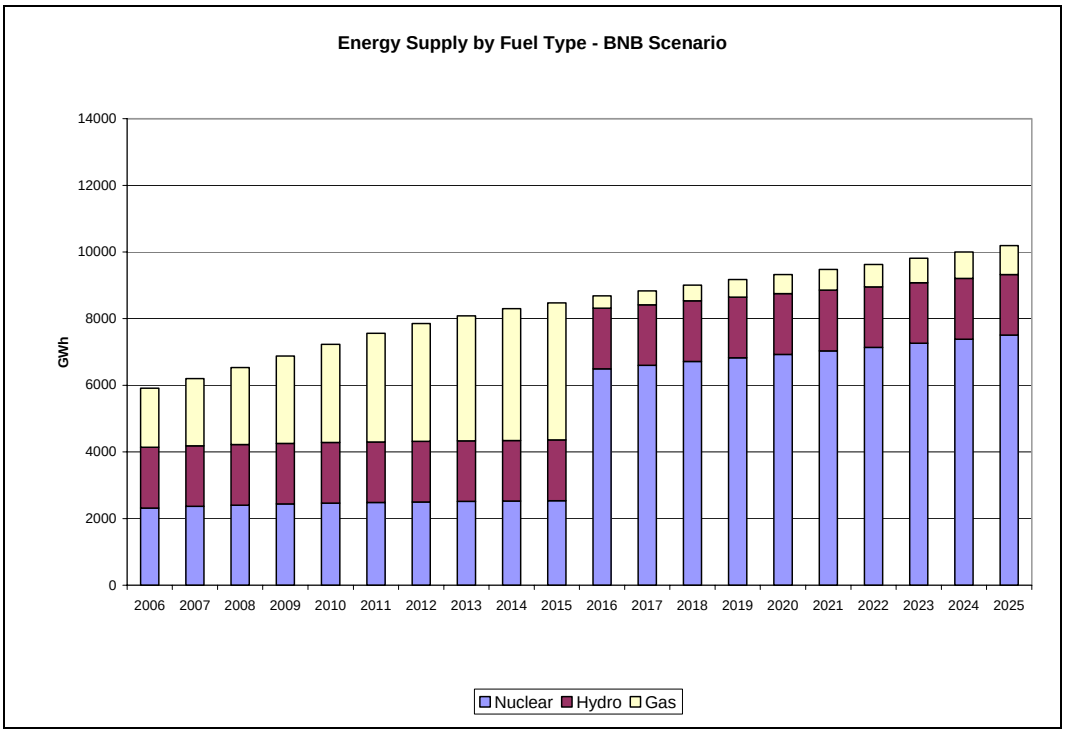
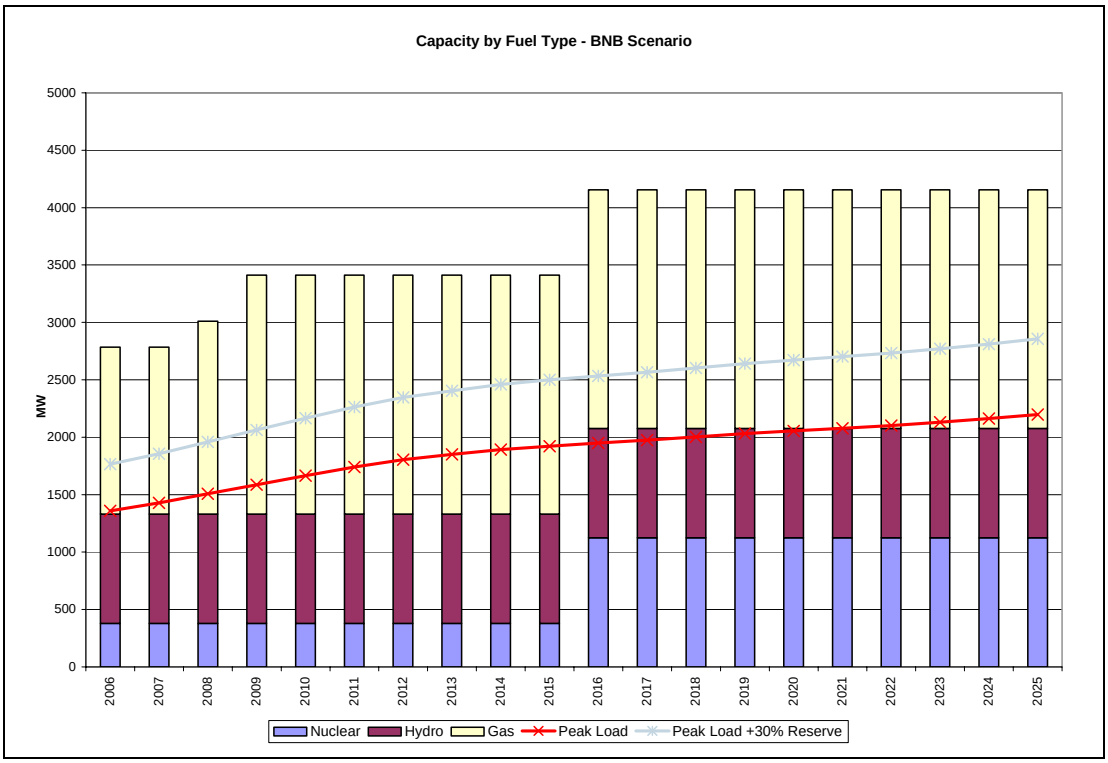


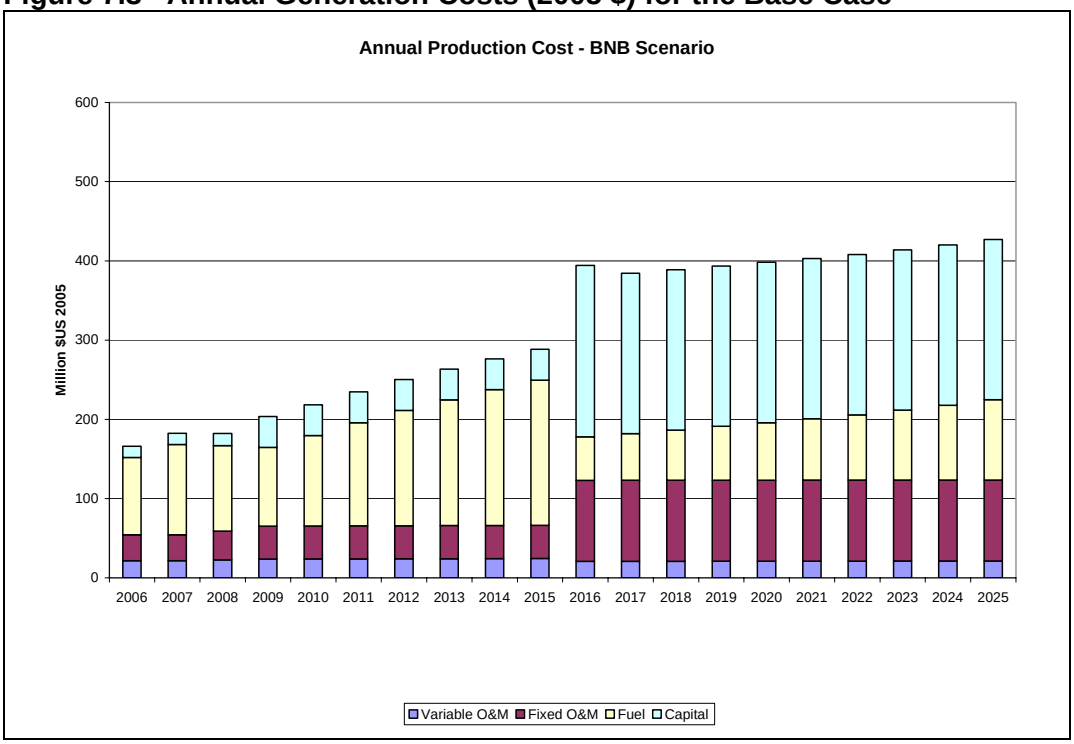
Figure 7.2 Generating Capacity Mix by Fuel Type for the Base Case



7.2.3 Annual Generation Costs

Figure 7.3 depicts the annual costs, in 2005 dollars, for generation to meet energy requirements of the system.

Figure 7.3 Annual Generation Costs (2005 $) for the Base Case



7.3 DEMAND FORECAST IMPACT

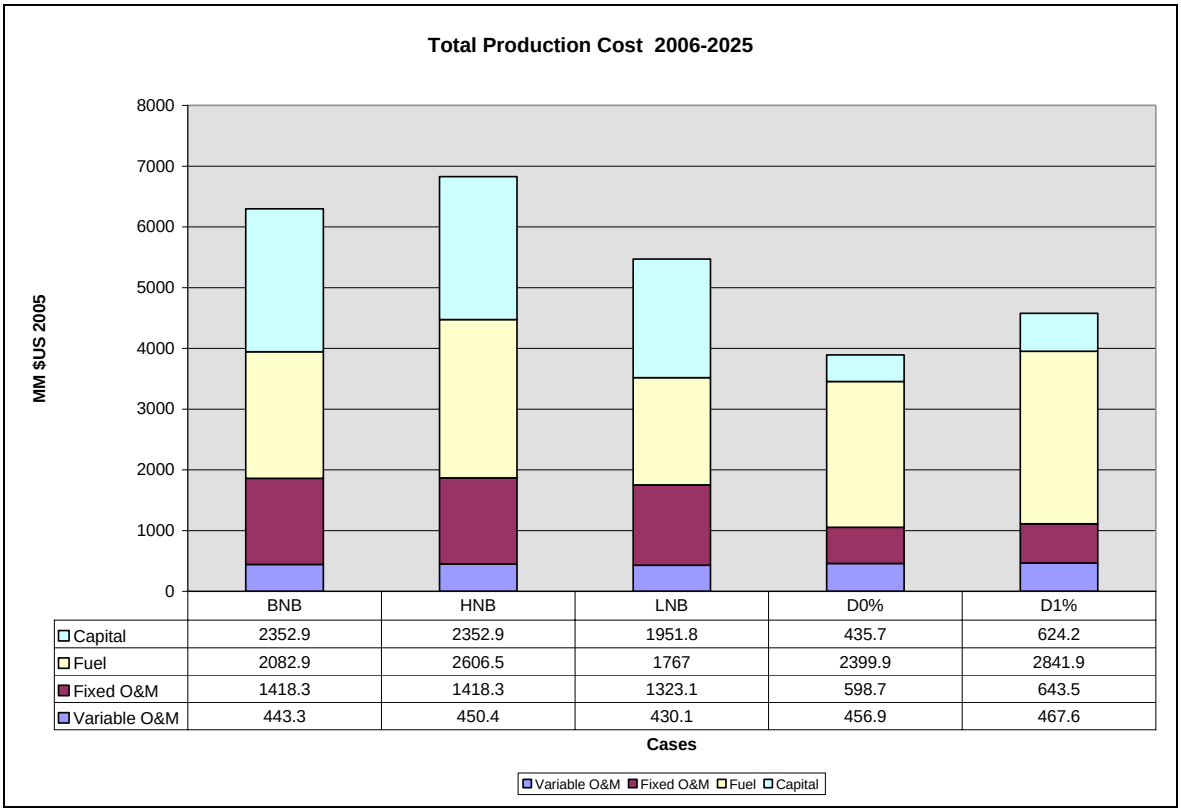
To assess the impact of electricity demand, four additional cases, High and Low demand forecasts as well as hypothetical 0% and 1% growth rates, were analyzed.

It should be noted that the Demand Factor plays a significant role in optimization process and optimal solutions. In addition to the use of total production value, different levels of forecasted demand and other constraints are considered by the industry for system optimization. One of the major constraints, from system reliability point of view, in cases of 0% and 1 % demand growth, is the unit size. Based on these hypothetical low demand growth assumptions and the assumption that there is no export opportunity on a firm basis, the construction of a new 1000 MW nuclear unit is not the best option. For these cases, the model's optimal solution is to replace the existing thermal units with new and more efficient natural gas fired units. The major risks for this solution are; lack of diversity in fuel mix, fuel supply interruptions, and potential high cost of gas. .

The optimal solution proposed by the IPM model for more realistic cases, such as High and Low demands forecasts, is similar or very close to the Base Case. The Model proposes the construction of a new nuclear unit and replacement of existing thermal capacities wherever it is possible from a system economic dispatch point of view. Another conclusion that was reached, based on a study of these cases, was that the optimal solution between new thermal and new nuclear technologies (LNB case) is nuclear.

Present values of system generation costs for different cases are shown in Figure 7.4. Capacity additions and changes proposed by IPM Model for different cases are presented in Tables 7.3 to 7.6.

Figure 7.4 Net Present Values of System Generation Costs for Base, High, Low, 0% and 1% Demand Growth Cases



	BNB	HNB	LNB	D0%	D1%
Capital	2352.9	2352.9	1951.8	435.7	624.2
Fuel	2082.9	2606.5	1767	2399.9	2841.9
Fixed O&M	1418.3	1418.3	1323.1	598.7	643.5
Variable O&M	443.3	450.4	430.1	456.9	467.6

Table 7.3 Capacity Additions and Retirements for the High Demand Case

Case	Year	2008	2009	2016
HNB	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP 2016

Table 7.4 Capacity Additions and Retirements for the Low Demand Case

Case	Year	2008	2016
LNB	Capacity Addition	225 MW Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP 2016

Table 7.5 Capacity Additions and Retirements for the 0% Demand Growth Case

Case	Year	2008	2015	2016
D0%	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT	
	Capacity Retirement			ANPP 2016

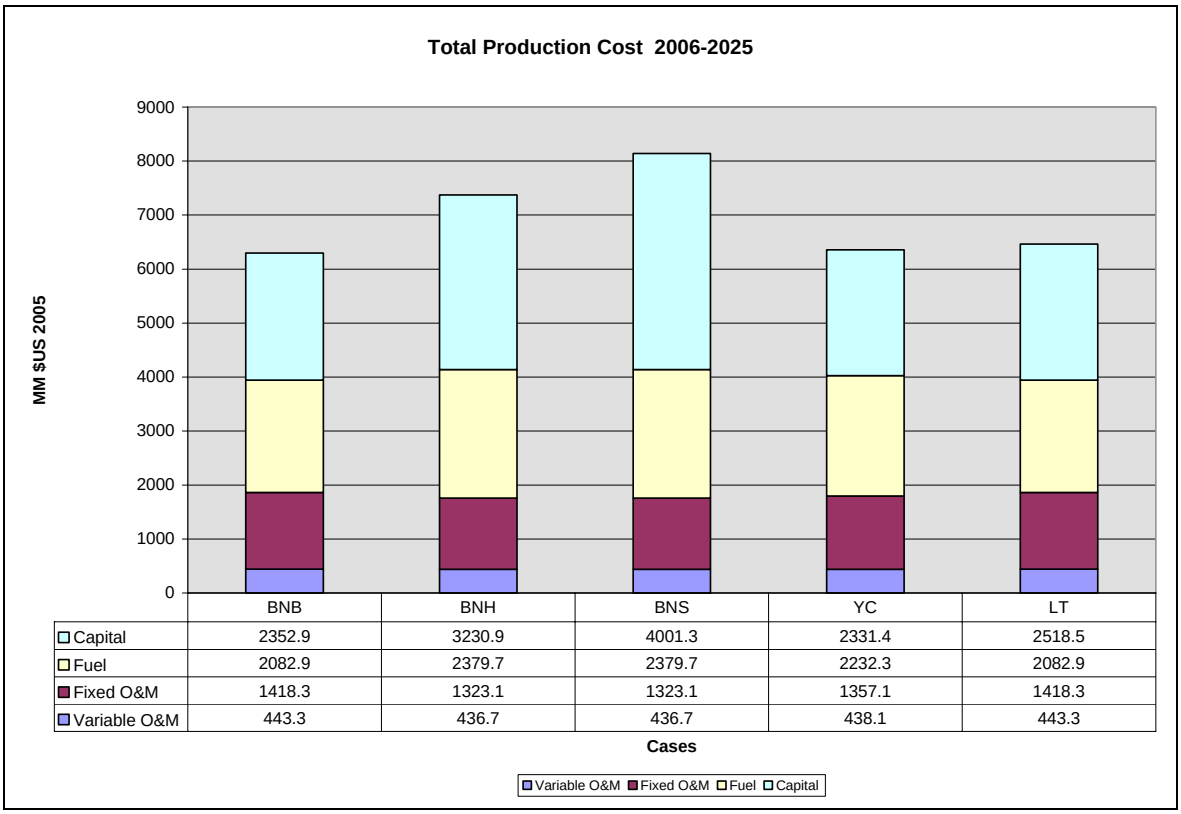
Table 7.6 Capacity Additions and Retirements for the 1% Demand Growth Case

Case	Year	2008	2011	2016	2022
D1%	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT		400MW CCGT
	Capacity Retirement			ANPP 2016	

7.4 IMPACT OF VARIOUS WACC

Variety of cases was studied to analyze the cost of capital impact on optimal solution. Although the construction of a new nuclear unit remains the optimal solution to replace the existing ANPP in 2016 for all cases, the higher cost of capital reduces the attractiveness of existing thermal generation replacement (BNH, BNS). One case (YC) was analyzed to evaluate the impact of the JBIC's soft loan. For YC case, it was assumed that there are no soft loans or grants and all potential technologies have equal financing conditions. This assumption makes the construction of new 400 MW CCGT, in addition to a new nuclear unit, more preferable than a 225 MW Yerevan CCGT, in addition to a new nuclear unit. However, the economic attractiveness of replacement of obsolete thermal generation in general does not decrease. Another hypothetical case (LT) that was studied constrained limiting the design life of a new nuclear unit from 60 to 30 years, equal to the life of a new thermal unit. The results indicate that this change does not impact the optimum solution, the nuclear technologies. Figure 7.6 presents the net present value of system generation cost for abovementioned cases. The capacity additions and changes proposed by IPM Model for these cases are presented in Tables 7.7 to 7.10.

Figure 7.6 Net Present Value of System Generation Costs for Base, High and Sensitivity of WACC Cases, Commercial Capital and Unit Life variations



	BNB	BNH	BNS	YC	LT
Capital	2352.9	3230.9	4001.3	2331.4	2518.5
Fuel	2082.9	2379.7	2379.7	2232.3	2082.9
Fixed O&M	1418.3	1323.1	1323.1	1357.1	1418.3
Variable O&M	443.3	436.7	436.7	438.1	443.3

Table 7.7 Capacity Additions and Retirements for the High WACC Case

Case	Year	2008	2016
BNH	Capacity Addition	225 MW Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP 2016

Table 7.8 Capacity Additions and Retirements for the WACC Sensitivity Case

Case	Year	2008	2016
BNS	Capacity Addition	225 MW Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP 2016

Table 7.9 Capacity Additions and Retirements for the YC Case

Case	Year	2009	2016
YC	Capacity Addition	400MW CCGT	ACR 1000
	Capacity Retirement		ANPP 2016

Table 7.10 Capacity Additions and Retirements for the LT Case

Case	Year	2008	2009	2016
LT	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP 2016

7.5 RESERVE MARGIN IMPACT

Case 12 (25% Reserve) was studied to assess the impact of the reserve margin, which is assumed to be 30% for all cases.

The results indicate that the decrease in reserve capacity margin has no impact on the least cost option, a new nuclear unit. However, under this scenario, the construction of new thermal generation to replace the existing thermals units is not economically attractive.

Figure 7.7 presents the present value of system generation cost for reference (BNB) and 25% cases. Capacity additions and changes for these cases are presented in Table 7.11.

Figure 7.7 Net Present Value of System Generation Costs, 25% Reserve Margin Case

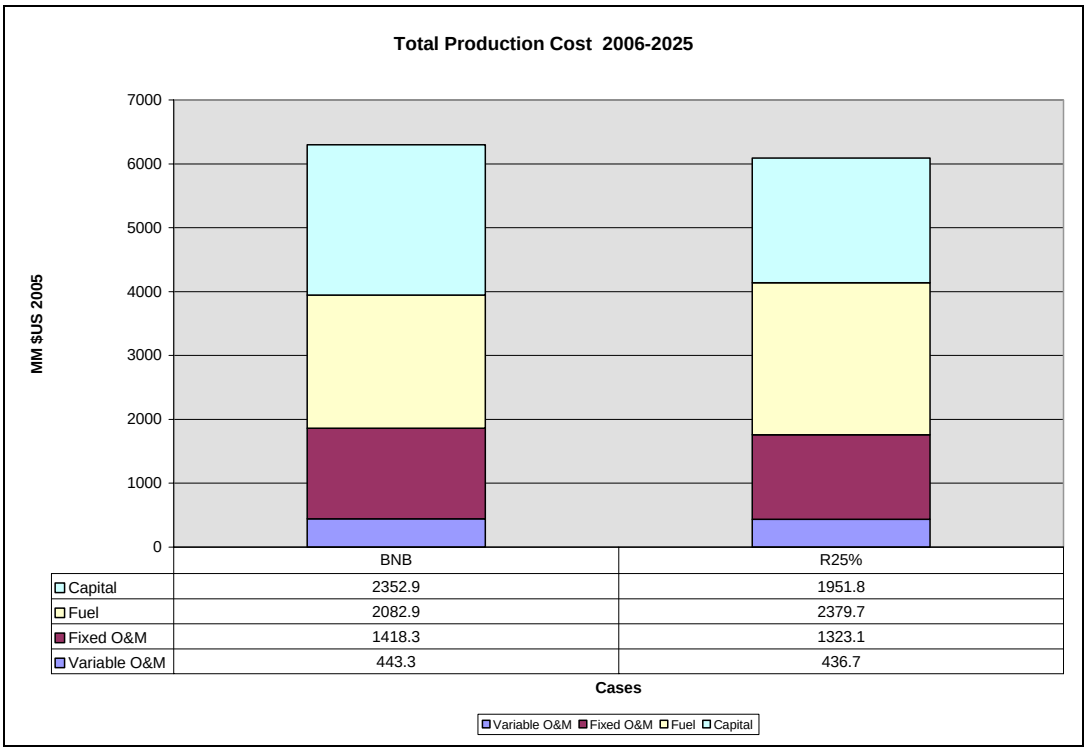


Table 7.11 Capacity Additions and Retirements for the 25% Reserve Case

Case	Year	2008	2016
25%	Capacity Addition	225 MW Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP 2016

7.6 CAPACITY TYPE LIMITATIONS

To assess the impact of constraining to build specific types of generation, two cases were analyzed. Case 8 (No_Nuce) assumes restriction on new nuclear unit construction and Case 9 (BNB_NT) – restriction on new thermal plants (except JBIC funded 225 MW Yerevan CCGT).

Figure 7.8 presents the system generation cost for abovementioned cases. Capacity additions and changes for these cases are presented in Tables 7.12 and 7.13.

Figure 7.8 Net Present Value of System Generation Costs for BNB, No_Nuce, and BNB_NT cases

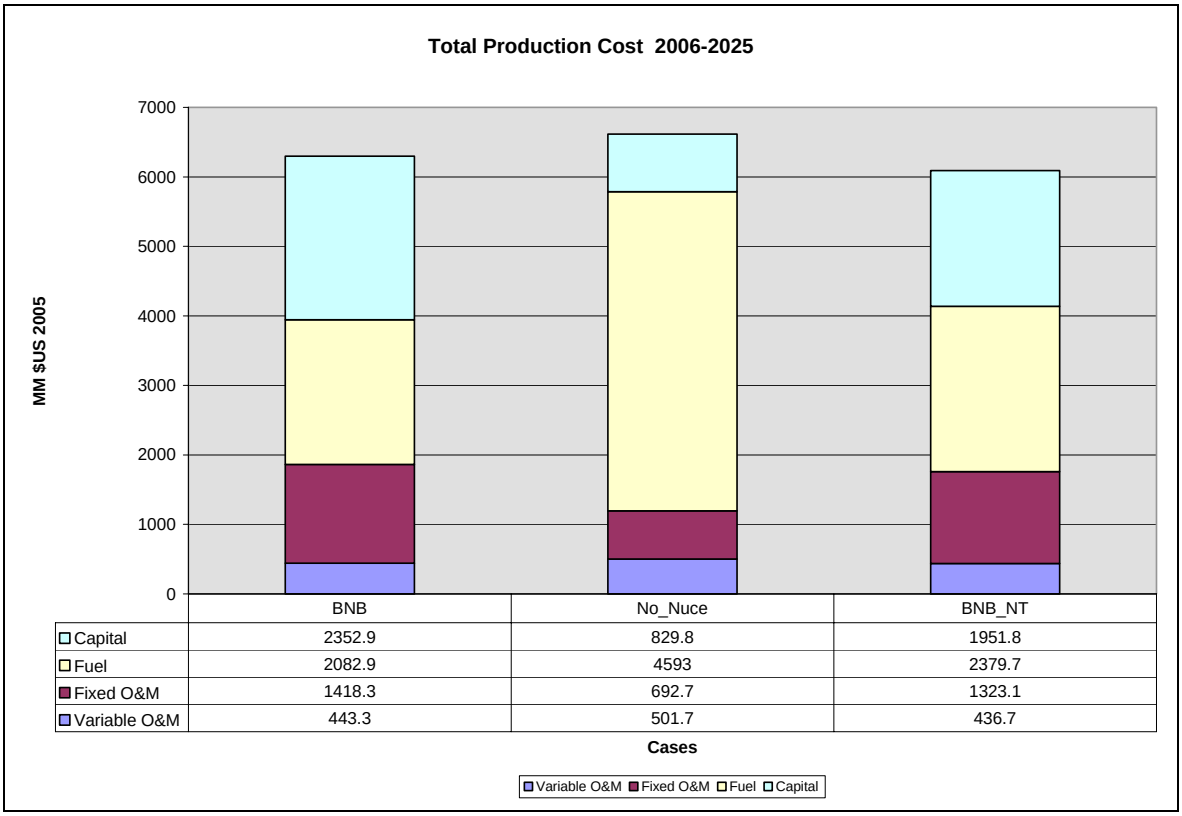


Table 7.12 Capacity Additions and Retirements, No_Nuce Case

Case	Year	2008	2009	2016	2018
No_Nuce	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT	225 MW CCGT	225MW CCGT
	Capacity Retirement			ANPP 2016	

Table 7.13 Capacity Additions and Retirements BNB_NT Case

Case	Year	2008	2016
BNB_NT	Capacity Addition	225 MW Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP 2016

Restriction for construction of a new nuclear unit will cost an additional $320 million (US$) within the planning horizon. The cost would be much higher if the difference in design life for thermal and nuclear units and a higher gas price forecast are considered.

Same conclusion could be made about the results of BNB_NT case, although the present value of total cost for BNB_NT case is lower than the reference case. Longer planning horizon, rapidly growing gas prices and retirement of the existing thermal units will completely change this picture.

7.7 IMPACT OF COMBINATION OF VARIOUS FACTORS

To assess the impact of various factors in different combinations, two additional cases were analyzed. Case 5 (HNH) assumes high demand forecast combined with a high WACC; Case 7 (LNH) – low demand combined with high WACC.

Although the total costs for these cases are different from each other and the reference case, the least cost solution remains within the range of the previous results. Figure 7.9 shows the comparison of Net Present Values of system generation costs for Base case and the considered combinations. Capacity additions and changes provided in Tables 7.14 and 7.15 highlights that high fuel prices would expedite the need for the construction of a new nuclear unit, despite the high WACC.

Figure 7.9 Net Present Value of System Generation Costs for BNB, TR and SMP cases

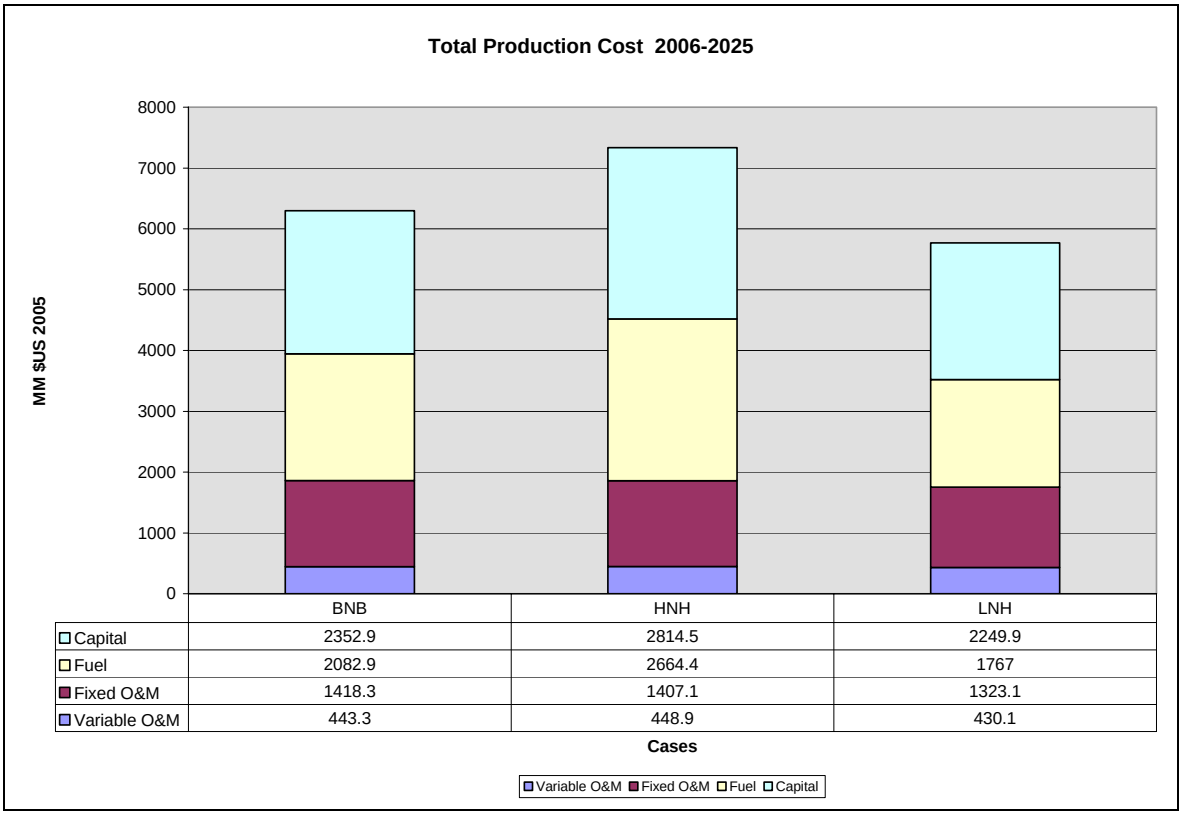


Table 7.14 Capacity Additions and Retirements HNH Case

Case	Year	2008	2011	2016
HNH	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP 2016

Table 7.15 Capacity Additions and Retirements LNH Case

Case	Year	2008	2016
LNH	Capacity Addition	225 MW Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP 2016

7.8 OTHER CASES

Two additional possible cases were found to be reasonable to consider. The first case was related to the retirement of existing thermal units (TR). Most of the existing thermal units in Armenia are very old, and some are beyond their useful life. However, these units should continue to operate “until the first major breakdown”. Although for most cases of the LCGP 2006 the study assumes that these units will remain available for operation or at least in a cold (non-spinning) reserve mode, the possible replacement of all obsolete units was considered within the scope of this LCGP.

The second additional case was the Strategic case (SMP), to determine the additional cost to electric consumers due to increased fuel diversity, by constructing hydro

generation. Figure 7.10 depicts the results of the base case along with TPP retirements and hydro generation construction.

Figure 7.10 Net Present Value of System Generation Costs for BNB, TR, and SMP cases

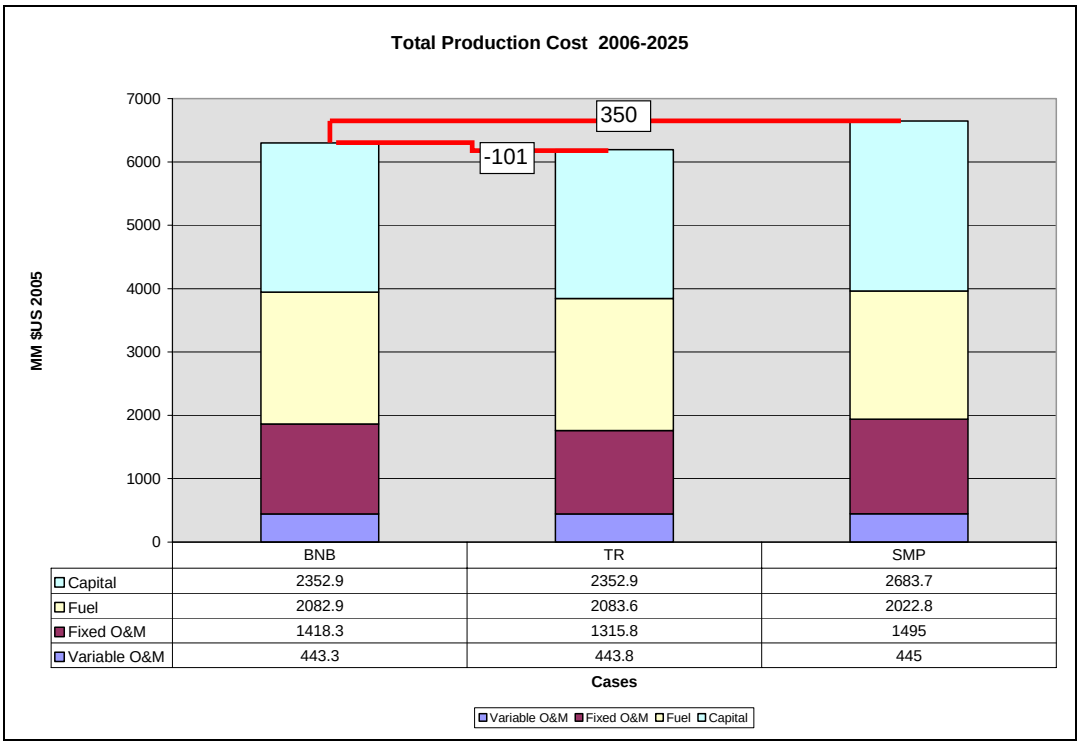


Table 7.16 Capacity Additions and Retirements, TR Case

Case	Year	2006	2008	2009	2016	2019
TR	Capacity Addition		225 MW Yerevan JBIC	400MW CCGT	ACR 1000	
	Capacity Retirement	Yerevan 1,2,4			Hrazdan existing; ANPP 2016	Yerevan 6,7

Table 7.17 Capacity Additions and Retirements SMP Case

Case	Year	2008	2011	2016	2017
SMP	Capacity Addition	225 MW Yerevan JBIC Hrazdan 5	225 MW CCGT Loriberd 60	ACR 1000	Shnokh 75
	Capacity Retirement			ANPP 2016	

The difference in NPV of system generation cost between reference and TR cases, shown on Figure 7.10 indicates that the TR case that assumes the retirement of existing thermal generation is attractive, since it reduces system fixed O&M costs.

The NPV difference in system generation cost between reference and SMP cases is shown on Figure 7.10. The SMP case will cost about $350 million more than the base case.

The tariff impact analysis is presented in the following section, and summary results of the 16 studied cases are provided in Appendix F.

7.8 Retail Tariff Analysis

Tariff analysis and impact assessment were conducted for the most probable scenarios/ cases that were studied. The analysis were performed utilizing a simplified approach that considered the wholesale tariff estimated by the IPM optimization model and the existing high-voltage and distribution margins, derived from the PSRC data, which are used in the tariff setting process.

The 2006 LCGP Update as well as LCGP 2005 focuses on the generation requirements of Armenian electric sector and does not included, in detail, future development of transmission and distribution networks. Thus, the plan does not forecast future investment requirements for the transmission and/or distribution system. Therefore for the purposes of tariff analysis, current estimated transmission and distribution margins were used to approximate final retail tariff values and compare impacts of different scenarios on tariff.

As was estimated in LCGP 2005, transmission margin including services (Power System Operation and Settlement Center) makes up 2.25 Mills/kWh, and distribution margin equals 15Mills/kWh. Details of margins' assessment as well as the description of how the tariff values were calculated on the basis of IPM outputs were provided in LCGP 2005. The results of tariff impact calculations for the most important scenarios of LCGP 2006 Update are provided in the following sections.

7.8.1 Future Electric Power Sector Development Impacts on Tariff

Several scenarios were chosen to estimate their impacts on tariffs. These scenarios are associated with the most probable tariff path: the Base Economic Case; two extremes – the highest and the lowest tariff path that might occur under No Nuclear Scenario and No Thermal Scenario, and several intermediate cases associated with High Cost of Capital Scenario, Strategic Ministry of Energy Plan Scenario, and Yerevan Commercial Scenario.

Potential tariff difference between the Base Economic Case and the case that assumes all old thermal generating units are retired (Step1 – 132 MW of Yerevan CHP's in 2006; Step2 - 1028 MW of Hrazdan TPP by 2016; Step3 - YTPP units 6 and 7 in 2019) by 2020 (Thermal Retirement) was analyzed to determine the burden on the rate payers if these units are retained for system reserve or retired and substituted with new generation.

Special consideration, from the tariff impact stand point, was given to the Strategic Ministry Plan Case that is described in the Energy Strategy of Armenia. For this case all strategic options were included, although they were never proposed for construction by the model due to their economic inefficiency. These options include Shnokh and Lori-Berd HPPS (Megri HPP, 140 MW, was not included in LCGP-2005 since it will start producing power for domestic market of Armenia after 2025), Yerevan CCGT financed at commercial cost of capital (this technology is commissioned in 2016) and Hrazdan Unit 5 - commissioned in 2008.

The comparison of scenarios for tariff impact indicates that:

- In all scenarios the tariff should raise during 2006-2007 as compared with 2005 to compensate for the increases in fuel costs on existing thermal power plants until the new CCGT is commissioned at Yerevan site in 2008;

- Commissioning of the Yerevan CCGT in 2008 will slightly reduce the tariff for a period of one year. After that starting from 2009 through 2015 the tariff will raise at a modest rate, between 1.5%-2.3% per year;

- In 2016 the tariff will increase sharply due to commissioning of new generation technologies;

- Base Load High Capital Case will have the highest impact on tariff during the entire study period. In this case the tariff will raise by 30 Mills/kWh in 2016 and will remain by almost 20 Mills/kWh higher through the period for all other scenarios except No Nuclear Scenario;

- In all other cases, other than Base Load High Capital Scenario, the tariff will also increase in 2016, but the increment will be of substantially smaller - about 12 Mills/kWh;

- In No Nuclear Scenario, from 2017, the tariff will start to increase such that by 2025 it will be 10 Mills/kWh higher than all other cases (except Base Load High Capital Case);

- Tariff impact of all other cases, other than No Nuclear and Base Load High Capital scenarios, are not so profound: during 2016-2025 price difference between these scenarios will be no greater than 5 Mills/kWh;

- Out of all other cases, other than No Nuclear and Base Load High Capital Scenarios, the Strategic Scenario will be the most costly: during 2016-2025 it will cost by 2-5 Mills/kWh more than the other cases.

The graphic comparison of the tariff analysis for the above cases is provided in Figure 7.16 and 7.17

It should be noted that the analysis only reflects the relative impacts of various scenarios and not the actual tariff. The actual tariffs will be calculated using a different methodology, and various approaches can be applied to increase the tariff gradually and prevent a step increases in tariff.

Detailed results of the tariff analysis are presented in Appendix F.

Figure 7.16 Tariff Comparison for selected Scenarios

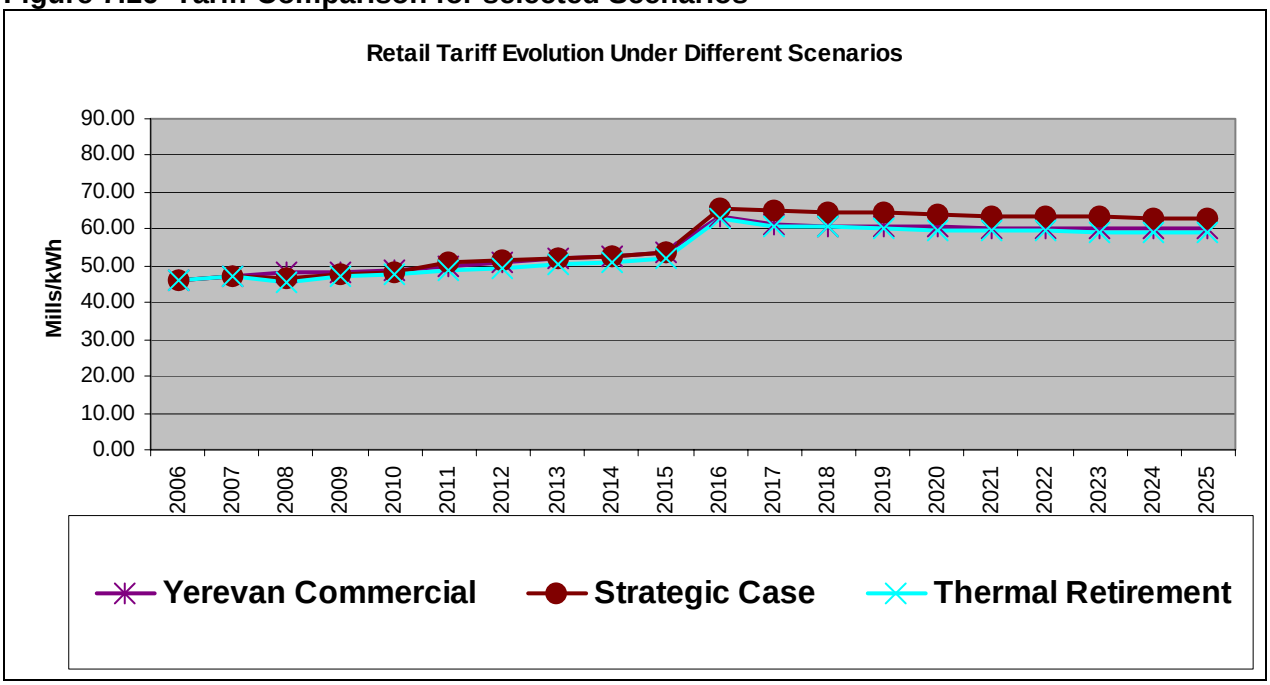
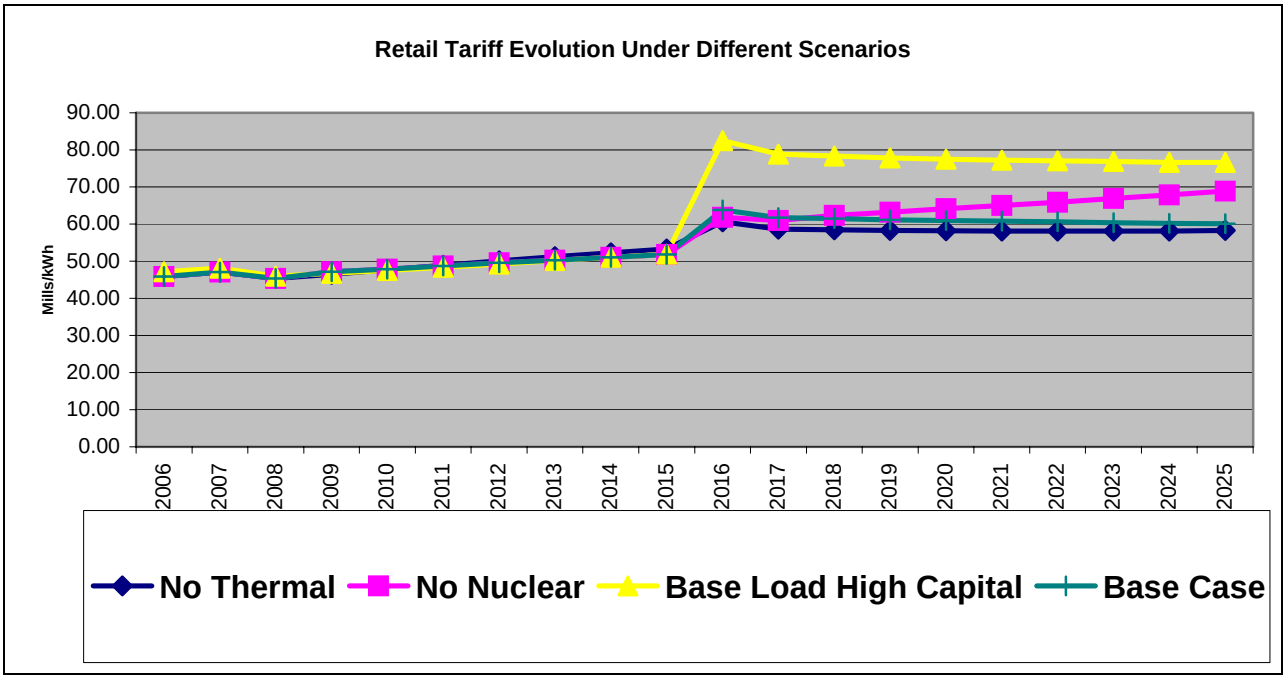


Figure 7.17 Tariff Comparison for selected Scenarios



8. CONCLUSIONS AND RECOMMENDATIONS

8.1 PREFERRED RESOURCE PLAN

Armenia's power sector abundance of generating capacities is coming to an end as ANPP approaches its designed life by 2016 and as many thermal plants have already exceeded their useful design life. Prior to replacing ANPP, construction of a new combined cycle gas turbine plant in 2008 could be beneficial provided preferential or privileged financing is available through JBIC as natural gas prices are expected to increase. To construct this plant for commercial operation in 2008, the detailed project planning should start in 2006.

There is no economic alternative to the continued operation of ANPP until its retirement in 2016. The GoA and the international donor agencies should agree to continued operation of ANPP and commit and provide the appropriate funding required to improve safety and reliability of the unit for its continued operational through the end of its design life (through 2015).

New gas prices make the replacement of existing thermal units more attractive due to their age and inefficiency.

Continued development of small hydropower plants should be encouraged due to their low cost and utilization of domestic energy resources. Planned low-cost financing supported by international agencies, revolving fund, should be established to continue the development of small hydro power plants and eventually other renewable resources.

Environmental Impact Assessment for a New Nuclear Plant in Armenia needs to be conducted. The objective of this task is to prepare plans for completing an Environmental Impact Assessment (EIA) of a new nuclear plant in Armenia. Completing the EIA is one of the early steps in the project for constructing a new nuclear plant in Armenia to replace the generating capacity of the existing Armenian Nuclear Power Plant (ANPP). The EIA, which typically requires up to three years to complete, is an essential first step in confirming the suitability of the site for the proposed unit(s) as well as obtaining commitments for financial support from Western funding agencies. In order to have the option for construction of a new nuclear plant to replace ANPP by the end of its design life in 2016, the preparation of the EIA must begin in 2006. The preparation of an EIA conforming to international standards and guidelines is a complex task, for which Armenia would need extensive support, due to lack of experience. Expert support will be needed to structure the plans, schedule, and budget for completing the EIA to international standards in a reasonable time frame. This assessment would also assist in determining site suitability for some of the decommissioning alternatives.

8.2 RECOMMENDATIONS

Based on the analysis performed and strategic and economic consideration, the following recommendations are provided:

- Decommission the ANPP in 2016;
- Conduct a comprehensive safety and environmental assessment of the ANPP site to determine the site's viability for decommissioning and construction of new nuclear generation;
- Develop a comprehensive decommissioning plan to be implemented 5 years prior to the commencement of ANPP's decommissioning;

- Determine the funding sources for decommissioning ANPP, establish a credible decommissioning fund, select a fund manager to mange the fund while investing in low risk investment monitored by international organizations;
- Fully fund the safety improvements and investment requirements of ANPP for its safe operation through 2015;
- Develop and implement a plan to address concerns regarding Armenia's ability to finance and construct new nuclear unit, including unit size and disposal issues;
- Develop and implement a plan to address concerns regarding Armenia's ability to replace existing thermal units at Hrazdan and Yerevan TPPs with new units;
- Develop indigenous renewable resources in order to increase energy independence and diversity;
- Develop and implement a plan that rewards Energy Efficiency, making it economically attractive to the consumers to invest in new equipment and applicants.
- Establish and implement a plan for minimizing the rate impact on consumers for ANPP decommissioning, and commissioning new generation capacity;
- Given the utility investment requirements, develop and implement a plan to address vulnerable consumers' needs for assistance.

8.3 TWO YEAR ACTION PLAN

There are several decisions that have to be made and action plans completed in the next two years to address the issues raised in this study.

The implementation phase of the 2005 LCGP is very important. The following two-year action plan for the Armenian power sector is proposed based on the results of the 2005 LCGP process.

- ANPP's decommissioning date has to be determined, formalized through passage of the law in the National Assembly, and communicated to the Armenian public and international organizations;
- A comprehensive safety and environmental assessments of the exiting ANPP site must be performed to determine the feasibility of the site for various decommissioning options and for potential new nuclear unit;
- A decommissioning study should be completed, decommissioning and waste disposal plans and standards should be developed, a decommissioning fund created, and collection of decommissioning costs from consumers included in retail rates;
- The costs related to safety improvements should be collected through retail rates and or provided through grants by international organizations, to ensure the continued safe operation of the ANPP;
- Fully fund and complete all capital improvements needed for safety improvements of ANPP as well as those required to continue operational through 2015;
- Perform detailed technical and economic analysis and explore financing approach and options for constructing new generation capacity prior to 2016;
- Develop a plan to address the following concerns in order to make new nuclear generation a viable option:

(a) The cost of constructing new nuclear generation in Armenia may be prohibitive;

(b) The sizing of the unit should take into account the existing system and a large unit option really could only make sense as part of a regional power market, which may be an uncertainty;

(c) Probable absence of capital for such a unit since its economic viability may depend on a regional market that presently doesn't exist;

(d) Absence of any credible waste disposal option;

- Priorities should be developed for all capital improvement programs to ensure that the utility consumers of Armenia can afford to pay for the most urgent improvements, not just in the electric sector, but in all public service sectors (water, natural gas, telephone, and electric transportation);
- The Public Services Regulatory Commission (PSRC) should develop a plan for minimizing the rate impact on consumers for ANPP decommissioning, and commissioning new generation capacity;
- Given that Armenia would need significant amount of investment in the energy sector, a significant number of consumers (pensioners, low income families) would need assistance for their utility services. The GoA should develop a plan, with donors' assistance, to put in place a social safety net/ utility assistance program for low income families/ pensioners;
- Continue the operation of the old thermal-powered plants for system reserve needs, no specific investment programs are needed apart from those, required for safe operation of the plant and employees, the thermal units should continue to be available to operate as long as there are no major failures or expensive maintenance or investment is required;
- PSRC should require from the distribution company to collect information regarding customers' electric use in order to determine the future load pattern and sales for each end-use for future analysis;
- Funding strategic projects should be closely examined and monitored by GoA and PSRC to minimize the impact on customers' tariff;

8.4 INVESTMENT REQUIREMENTS FOR PREFERRED RESOURCE PLAN

The investment requirements, as compared with the LCGP 2005, have increased by $277 million. The funds are needed for construction of a 400 MW CCGT to be commissioned in 2009 as proposed by the optimal generation strategy of the LCGP 2006 Update.

The following Table 8.4.1 provides year by year capital investments required by the energy sector for the preferred resource plan.

Table 8.4.1 Annual Investment Plan for the Preferred Resource Plan

Years	Thermal	Hydro	New Nuclear ACR-1000	Nuclear ANPP	Yerevan CCGT	Total
	(mln USD)					
2005				42.7		42.7
2006				39.4	43.8	83.2
2007	81.6			36.3	87.0	204.9
2008	169.4			33.5	14	216.9
2009	26			30.9		56.9
2010				18.4		18.4
2011			212.7			212.7
2012			539.3			539.3
2013			655.3			655.3
2014			437.4			437.4
2015			384			384.0
2016						0.0
2017						0.0
2018						0.0
2019						0.0
2020						0.0
2021						0.0
2022						0.0
2023						0.0
2024						0.0
2025						0.0
Total						**2851.7**

The table indicates only the funds needed for investment and does not show operation and maintenance costs.

APPENDIX A:

ANPP Upgrade Projects, Decommissioning, Life Extension and Replacement Issues and Cost

Armenian Power Sector 2006 Least Cost Generation Plan

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1. APPENDIX A-1: DECOMMISSIONING COST AND SCHEDULE FOR THE ARMENIAN NUCLEAR POWER PLANT

EXECUTIVE SUMMARY

The primary objective of this study is to develop information on the cost, schedule, and funding requirements for decommissioning the Armenian Nuclear Power Plant (ANPP) as part of the Least Cost Generation Plan for the Armenian power sector. An additional objective of the study was to develop recommendations for a strategic plan for ANPP decommissioning.

The purpose of decommissioning is to allow removal of some or all of the regulatory controls that apply to a nuclear site while securing the long-term safety of the public and the environment. Decommissioning involves the decontamination and dismantling of nuclear plant systems and structures, disposal of the resulting radioactive waste, management of spent nuclear fuel, and restoration of the plant site to a condition that allows removal of regulatory controls. Three general scenarios for nuclear facility decommissioning are:

- Immediate Dismantlement (DECON): The facility is decontaminated and radioactive wastes are treated, packaged and removed to an appropriate waste storage or disposal site.
- Entombment (ENTOMB). Radioactive structures, systems, and components are encased in a structurally long-lived substance, such as concrete, at the facility.
- Safe Storage (SAFESTOR): The facility is placed in a safe, stable condition and maintained in that state for an extended period, followed by decommissioning by DECON or ENTOMB.

This study investigated each of these scenarios as they would apply to ANPP. Because the Armenian government has not established a date for shutdown of ANPP, this study investigated decommissioning cost for plant shutdown at the end of 2009, 2015, and 2035.

A major factor in the cost for decommissioning is the cost for disposal of radioactive waste. In the case of ANPP, an existing low-level waste storage facility is located near the plant. However, this facility would have to be converted to a near-surface disposal vault and expanded substantially to allow disposal of all of the decommissioning waste. Alternatively, a new near-surface disposal vault facility could be constructed on the ANPP site or elsewhere in Armenia. Another alternative may be to use the ANPP reactor buildings as the final disposal vault for the radioactive waste.

The cost of final disposal of SNF, while not usually included in decommissioning costs, represents a substantial future cost for ANPP that is currently unfunded. SNF has been accumulating at the plant since it was restarted in 1995. Returning the SNF to Russia for reprocessing is the only technically and economically feasible disposal option. However, this option is not currently available and the timing and cost cannot be estimated accurately until a plan for SNF disposal is defined. A range of estimates for potential Russian fuel disposal fees was developed from review of the literature. The cost for disposal of the current spent fuel inventory is potentially larger than the plant's decommissioning cost.

There have been two previous studies of the decommissioning costs for ANPP performed by decommissioning experts from Sogin of Italy and PNNL in the US. The Sogin study

performed a detailed estimate of costs for a SAFESTOR/DECON scenario and extrapolated those results to estimate costs for immediate DECON. The PNNL study investigated costs for DECON, ENTOMB, and several SAFESTOR scenarios. The reported cost estimates of the Sogin study are much higher than the costs for equivalent scenarios in the PNNL study. However, after accounting for differences in assumptions on labor cost escalation and waste disposal, the SOGIN and PNNL estimates produced similar values. The PNNL assumptions are more appropriate to the situation in Armenia and provide a better basis for further evaluation of decommissioning cost. The cost estimates produced by these studies are also consistent with the range of decommissioning cost estimates for VVER 440 plants in other countries that was prepared by IAEA.

SCIENTECH performed a detailed review of the cost elements of the various PNNL cost estimate scenarios by developing cost estimates for the SAFESTOR and ENTOMB scenarios based on estimates recently prepared for a pressurized water reactor plant in the US. The US reference plant estimates were adjusted to match conditions at the ANPP. The reference plant estimates were compared to the cost elements of the PNNL estimates to identify areas for detailed analysis that identified some areas in which adjustments are recommended. These areas were primarily related to the need for an increased level of support from decommissioning experts during the planning and dismantlement phases of decommissioning and to more recent information on SNF inventory. The recommended adjustments increase the estimated decommissioning costs by less than 20 percent, within the PNNL contingency band of 25 percent.

The adjusted decommissioning cost for each of the decommissioning scenarios for ANPP shutdown at the end of 2009 is shown in table S-1.

Table S-1: Adjusted PNNL Decommissioning Cost Estimates for 2009 ANPP Shutdown (Millions of 1999 US Dollars)

	DECON	SAFSTOR/ DECON 2	ENTOMB	SAFSTOR/ ENTOMB 2
D&D Activities	120.8	179	104.9	163.1
Sight Restoration	20	20	20	20
Rad Waste Management	31.3	26.5	16.7	16.1
Spent Fuel Management	19	19	19	19
Total	191.1	244.5	160.6	218.2
Contingency (25%)	47.775	61.125	40.15	54.55
Estimated Cost for Decommissioning	**238.875**	**305.625**	**200.75**	**272.75**
Spent Fuel Disposal	143-358	143-358	143-358	143-358
Total Costs	**382-597**	**449-664**	**344-558**	**416-631**

The previous decommissioning cost estimates were calculated in constant 1999 dollars. Because the decommissioning work will not start for several years and will be performed over a period of many years in the future, the information from the decommissioning cost estimates was used to calculate escalated present values to account for escalation and for the present value of money. The calculations assumed an escalation rate of one percent per year for decommissioning costs and an interest rate of four percent per year for a low risk investment of decommissioning funds. The results of the escalated present value calculations of decommissioning costs for plant shutdown at the end of 2015 are shown in tables E-2.

Table E-2: 2016 Present Value of Escalated Decommissioning Cost Estimates for 2015 ANPP Shutdown (Millions of US Dollars)

Decommissioning Scenario	Cost in 1999 $	Escalated Cost	2016 Present Value
DECON	238.8	298.1	241.4
SAFSTOR/ DECON 2	290.7	513.8	186.9
ENTOMB	200.7	248.8	206.8
SAFESTOR/ENTOMB 2	272.7	446.8	176.4

The results show that, although the scenarios involving SAFESTOR have a higher total cost, they have a lower present value because a large portion of the cost is deferred 40 years into the future. However, it should be noted that the escalated present value results are very sensitive to the difference between the assumed escalation and discount rates. The SAFESTOR scenarios have a much greater financial risk if escalation in construction costs over the next 50 years is higher than the general rate of inflation reducing the difference between the escalation rate and the discount rate. With escalation rates of three percent, the SAFESTOR scenario becomes more expensive on a present value as well as an absolute basis.

The Armenian government has not yet established a decommissioning fund for ANPP. Internationally, a commonly used funding method is an electricity rate surcharge on the kWh tariff on nuclear plant generation to collect the needed decommissioning funds over the remaining life of the plant. The information from the cost estimates was used to estimate the surcharge needed to accumulate the necessary decommissioning funds over the period starting in 2006 and extending through 10 years after plant shutdown, based on shutdown in 2009, 2015, or 2035. The results show that, for shutdown in 2009 or 2015, the surcharge for decommissioning would result in a 30 to 70 percent increase in the price of ANPP generation.

An alternative approach would be to put a surcharge on all electricity consumed in Armenia. Based on shutdown in 2015, the surcharge for decommissioning would increase the average electric rates by about 7 percent. It is recommended that the application of the surcharge to total consumption for a period ten years after shutdown be used as an initial basis to establish decommissioning funding surcharges.

To estimate the surcharge required to pay for future disposition of spent fuel, several scenarios were investigated. These scenarios covered variations in ANPP shutdown date, SNF disposal date, and escalation in disposal fees. For these scenarios, the surcharge to fund SNF disposal range from $1.7 to 27 million per year. The results demonstrate the sensitivity of the cost for spent fuel disposal to assumptions on the timing and escalation of disposal fees. For scenarios involving significant escalation in disposal fees, the surcharge needed for SNF disposal is much higher than the decommissioning surcharge. Determining the appropriate surcharge for SNF disposal will require defining a disposal plan.

Besides being the lowest in total cost and shortest schedule, the ENTOMB scenario has a number of technical, regulatory, and social advantages for the decommissioning of ANPP. In the dismantlement scenario, a radioactive waste disposal facility with sufficient capacity for ANPP decommissioning waste must be constructed at the ANPP site or some other location in Armenia. If the low level radioactive waste is entombed in the existing reactor buildings, construction and licensing of a separate radioactive waste disposal facility will not be necessary. A comprehensive performance assessment of the ANPP reactor

building and surrounding environment to evaluate its suitability as a radioactive waste disposal system should be performed as early as possible to determine the feasibility of the ENTOMB scenario. The data and methods of this entombment performance assessment could also be used in the performance assessment of a new or expanded waste disposal facility to be used in the DECON scenario.

The PNNL report[9] describes the plan and schedule for the tasks to be accomplished during each of the scenarios for decommissioning of ANPP and these plans are summarized in Annex A. In addition, section 8 presents a strategic plan for preparing for ANPP decommissioning. This strategic plan addresses regulatory, technical, organizational, and planning issues that should be addressed in the near term. Of particular importance are the elements to establish the decommissioning fund, to set in place the legal and regulatory framework, and to perform a decommissioning safety assessment.

ACRONYMS AND ABBREVIATIONS USED IN THE REPORT

ALARA - as low as reasonably achievable

ANPP - Armenian Nuclear Power Plant

ANRA - Armenian Nuclear Regulatory Authority

CECP - Cost Estimating Computer Program

DECON - Immediate Dismantlement

DPIPs - Decommissioning Plan Implementation Procedures

DOE - Department of Energy

ERC - Energy Regulatory Commission

ENTOMB - Entombment

HSM - horizontal storage module

IAEA – International Atomic Energy Agency

KgHM - Kilogram of heavy metal)

NEA - Nuclear Energy Agency

NPT - Non-Proliferation Trust

NRC – (US) Nuclear Regulatory Commission

MoE - Ministry of Energy,

OECD - Organization for Economic Co-Operation and Development

PNNL - Pacific Northwest National Laboratory

SAFESTOR - Safe Storage

SNF - spent nuclear fuel

US – United States

1. INTRODUCTION

The primary objective of this study is to develop information on the cost, schedule, and funding requirements for decommissioning the Armenian Nuclear Power Plant (ANPP) as part of the Least Cost Plan for the Armenian power sector. The study evaluated feasible decommissioning options for the ANPP to provide data and information needed by decision-makers to make the selection of decommissioning option and funding methods. An additional objective of the study was to develop recommendations for a strategic plan for ANPP decommissioning.

The ANPP consists of two VVER-440/270 pressurized water reactors. The VVER-440/270 design is similar to the VVER-440/230 with additional features for resistance to seismic events. All VVER-440s are built in modules of two units housed in a single reactor building. Unit 1 of the ANPP became operational in 1976 and unit 2 in 1980. Although both units continued to operate after the earthquake in December 1988, the government ordered the shutdown of both units in early 1989 for safety reasons. Unit 1 remains in a long-term shutdown mode and unit 2 was restarted in November 1995.

Based on 30-year design life of reactor vessel, ANPP unit 2 could continue to operate through 2015. However, there have been several proposals to shutdown unit 2 earlier because of concerns with the safety of the VVER-440/230 reactor design. There has also been consideration of extending the life of the ANPP for an additional 20 years, as has been done in the US. For this reason, this study investigated decommissioning cost for plant shutdown at the end of 2009, 2015, and 2035.

The safety of ANPP is regulated by the Armenian Nuclear Regulatory Agency (ANRA). ANRA is currently developing a “Plan for Licensing Preparation for the ANPP Decommissioning”. In compliance with the plan mentioned above, it is anticipated to develop and to put into force several regulatory documents necessary for preparation and decommissioning of ANPP. The planned timeframe for completion of these documents extends through 2007. These regulations will define acceptable practices for decommissioning and safety standards for decommissioning activities.

The approach used to gather information for this study included interviews with Managers at ANPP, Ministry of Energy (MoE), and ANRA; reviews of previous studies of ANPP decommissioning; reviews of surveys of decommissioning costs at other VVER-440 plants; and comparisons to plans and cost estimates recently prepared by SCIENTECH for a pressurized water reactor plant in the US.

2. NUCLEAR PLANT DECONTAMINATION AND DECOMMISSIONING (D&D)

The purpose of decommissioning is to allow removal of some or all of the regulatory controls that apply to a nuclear site while securing the long-term safety of the public and the environment. The objective is to achieve an endpoint that is sensible in technical, social and financial terms. Decommissioning involves the decontamination and dismantling of nuclear plant systems and structures, disposal of the resulting radioactive waste, management of spent nuclear fuel, and restoration of the plant site to a condition that allows removal of regulatory controls. Disposal of the spent nuclear fuel is not typically considered as part of decommissioning but is considered in this study because of the significant potential cost impact. General approaches for decommissioning, radioactive waste disposal, and spent fuel disposal are discussed in the following sections.

2.1 DECOMMISSIONING STRATEGIES

There are three broad types of decommissioning alternatives currently recognized: DECON, SAFESTOR, and ENTOMB. A description of each of these alternatives is provided below. In any actual decommissioning project some combination of these alternatives may be used.

Immediate Dismantlement (DECON). The equipment, structures, and portions of the facility that contain radioactive contaminants are removed or decontaminated to a level that permits termination of the facility license shortly (10-15 years) after cessation of operations. Radioactive wastes are treated, packaged and removed to an appropriate waste storage or disposal site. The advantages of the DECON approach are that the site is available for alternative use in a relatively short period and that a portion of the operating plant staff may be employed in the decommissioning work.

Safe Storage (SAFESTOR). The facility is placed in a safe, stable condition and maintained in that state for an extended period (e.g., 40-60 years) until it is subsequently decontaminated and dismantled to levels that permit license termination. During this period, the facility is left intact, but the fuel has been removed from the reactor vessel and radioactive liquids have been drained from systems. Radioactive decay occurs during the SAFESTOR period, reducing the quantity of radioactive material that must be disposed of during decontamination and dismantlement. The principal advantages of the SAFESTOR approach are reduced personnel radiation exposure and deferral of costs for a major portion of the decommissioning work. For a location such as Armenia with a single nuclear plant, a disadvantage of SAFESTOR is that there may not be a nuclear trained workforce, knowledgeable about the facility, available during the dismantlement period. This situation would require more expensive contractor support. Another disadvantage of SAFESTOR is the potential for escalation of labor and other decommissioning costs during the SAFESTOR period.

Entombment (ENTOMB). Radioactive structures, systems, and components are encased in a structurally long-lived substance, such as concrete. The entombed structure is appropriately maintained, and continued surveillance is carried out until the radioactivity decays to a level that permits termination of the license, which may take over one-hundred years. The principal advantage of the ENTOMB approach is that it eliminates a substantial portion of the cost and radiation exposure associated with removing the radioactive waste to a disposal facility. However, the entombed reactor will have radionuclides in concentrations exceeding the limits for unrestricted use even after 100 years, and continued security and regulatory control of the site will be required. A comprehensive safety and environmental assessment must be performed to provide assurance that release and dispersion of the radionuclide content in the entombment site

is adequately controlled and meets the regulatory criteria throughout the decay period required to achieve unrestricted release.

Although entombment has not been used for commercial nuclear power stations, it has been used on a number of research/demonstrative reactors as well as weapons complex facilities in the US. Both the U.S. and the International Atomic Energy Agency (IAEA) are giving renewed consideration to the use of entombment as an acceptable decommissioning method for nuclear power plants. In 1999, the IAEA issued TECDOC-1124, *On-Site Disposal as a Decommissioning Strategy*, [(14)] which concluded that, subject to safety and environmental protection assessment, entombment can be a viable decommissioning option and should be taken into consideration in decision making. Also in 1999, the US Nuclear Regulatory Commission (NRC) issued SECY-99-187, *Information Paper on the Viability of Entombment as a Decommissioning Option for Power Reactors* [(17)], which presented the results of assessments of entombment scenarios for commercial nuclear plants and concluded that consideration of entombment as a viable decommissioning option has merit. The NRC staff held a workshop to solicit stakeholder views on the technical bases, issues, and options for treating entombment equally with the other decommissioning alternatives. Several utilities indicated that they would like to have entombment available as an option, although none committed to using it. In 2000, the findings from the workshop were reported in SECY-00-0129, *Workshop Findings on the Entombment Option for Decommissioning Power Reactors and Staff Recommendations on Further Activities*[(18)]. In late 2001, the NRC issued SECY-01-0099, *Rulemaking Plan and Advance Notice of Proposed Rulemaking: Entombment for Power Reactors* [(19)] describing a plan to amend regulations to allow nuclear plant entombment with termination of the operating license. In 2002, the rule making plan was deferred because NRC resources were focused on security issues and no additional US nuclear plant decommissioning projects were anticipated in the near future. However, the Generic Environmental Impact Statement [(20)] for nuclear plant decommissioning was revised to include consideration of entombment as a decommissioning strategy. Subsequently, the NRC has continued to sponsor research studies directed at entombment viability issues.

In the case of ANPP, the ENTOMB strategy is particularly advantageous. This approach is potentially the lowest cost and would have the lowest radiation exposure to the workers and the public. Under the DECON approach, decommissioning waste from dismantlement of ANPP would probably go into a waste disposal facility constructed on the ANPP site, because there are no other radioactive waste disposal sites in Armenia. If the ANPP site is an acceptable disposal site for radioactive waste, then using the reactor building as an entombment structure may provide a good technical solution because of its robust engineered barrier features and because it has a substantially lower cost than dismantlement.

Any proposals for a nuclear waste disposal site give rise to significant public concern, which can also influence regulatory and government policy. It is therefore vital in making proposals for either a new radioactive waste disposal for decommissioning waste or for entombment that rigorous safety assessments are completed and that the environmental impacts are thoroughly explored and debated. If safety assessments demonstrate that the existing reactor buildings provide reliable, long term confinement of radionuclides to prevent their release into the environment, the ENTOMB strategy will provide the best technical and least cost solution to disposal of decommissioning waste.

2.2 LOW AND MEDIUM ACTIVITY WASTE DISPOSAL

A major factor in the cost for decommissioning is the cost for disposal of radioactive waste. This waste includes solid and liquid radioactive wastes remaining onsite from plant operation as well as waste generated by decommissioning. These wastes include low-

level, medium-level, and high-activity solid wastes and liquid radioactive wastes. Because of the unique characteristics of each class of radioactive waste, each must be processed, interim stored, and disposed in uniquely different ways. Low-level solid waste is compacted where possible and packaged in metal boxes or drums. Liquid waste must be concentrated through evaporation or other means. The liquid waste sludge is solidified and packaged in metal boxes or drums. Medium-level solid waste is usually over packed in high-integrity containers. High-activity waste must be cut up to fit into storage with spent fuel.

In many countries, low and medium level wastes are transported to dedicated waste disposal facilities. These facilities are typically below ground vaults or trenches in environmentally stable areas. The fees charged by operators of waste disposal facilities can be a major factor in overall decommissioning costs.

In the case where national disposal facilities are not available, nuclear plant decommissioning will require construction of a waste disposal facility. The facility must be located in an environmentally stable area and operated under a license from the country's nuclear regulator.

In the case of ANPP, an existing low-level waste storage facility is located near the plant. However, this facility does not have the capacity to accept the decommissioning waste from ANPP. This facility would have to be converted to a near-surface disposal vault and expanded substantially to allow disposal of all of the decommissioning waste. Alternatively, a new near-surface disposal vault facility could be constructed on the ANPP site. Expansion or construction of a low level radioactive waste facility will require environmental and safety assessments to demonstrate that radiation exposure to the public will be within regulatory limits.

As discussed above, another alternative may be to use the ANPP reactor buildings as the final disposal vault for the radioactive waste. This approach would be considerably less costly and avoid having to move the radioactive waste from one area on the ANPP site to another area just a couple of hundred meters away. Also, the foundation and structure composing the reactor building is a vastly more robust engineered structure for the containment of radioactive waste than the existing low-level waste disposal facility.

3. SPENT NUCLEAR FUEL INTERIM STORAGE AND DISPOSAL

ANPP generates on average 90 to 100 spent nuclear fuel (SNF) elements each year from the generation of electric power by Unit 2. After discharge from the reactor, SNF assemblies are placed into temporary storage in the cooling pools associated with each reactor. There are 621 SNF elements currently in dry storage in 11 dry storage modules at the ANPP site. At the end of 2004, there were 545 elements in the spent fuel pools, which have capacity of 750. An additional 349 elements could be stored in the unit 1 reactor vessel. Additional dry storage modules will be required for fuel assemblies for operation beyond 2009.

Prior to 1992, SNF elements were returned to Russia for reprocessing at the Mayak Chemical Compound. However, since restart of ANPP unit 2, there have been no shipments of SNF to Russia and SNF has continued to accumulate within the ANPP cooling pools. The SNF elements will need to be removed from the plant prior to decommissioning of the reactor building. The ANPP will have between 1,974 and 2,562 SNF elements on site after permanent shutdown of the plant, depending on whether the plant permanently shuts down in 2009 or 2015, respectively.

ANPP is currently planning to build additional dry storage modules for SNF. Construction is planned to be carried out in 3 phases: the first part will be operated in 2007, the second part in 2012 and the third part in 2018. The first two will provide for the storage of 672 cassettes each, and the third one – of 560 cassettes.

The costs for interim storage and disposal of SNF are not usually considered in decommissioning cost estimates. In most countries, funding for these costs is accumulated from operating revenues and they are considered as part of the operating costs. However, in Armenia, no funding for SNF has been established. For this reason, a discussion of the alternatives and approximate costs for SNF disposal and interim storage are presented in the following sections.

3.1 SPENT NUCLEAR FUEL DISPOSAL

One option for final disposition of the SNF from ANPP would be to construct a deep geologic disposal facility in Armenia. A geologic disposal facility for permanent waste disposal would be located underground (usually more than several hundred meters below the surface) to provide long term isolation of radioactive material from the environment. The facility would include a combination of geological characteristics, engineered barriers, and waste packaging to isolate the SNF. However, for a permanent repository, the geological characteristics of the site are crucial.

Construction of a geologic disposal facility in Armenia would probably require funding from other countries that would insist that the facility meet IAEA safety and environmental standards. IAEA guidelines for underground disposal facilities include the following criteria:

- The repository shall be located at sufficient depth to protect adequately the emplaced waste from external events and processes, in a host rock having properties that adequately restrict the deterioration of physical barriers and the transport of radionuclides from the repository to the environment. ….. The possibility of tectonic, seismic and other disturbances which can create new paths for the transport of radionuclides shall also be carefully evaluated[(2)].

- The host rock should not be liable to be affected by future geodynamic phenomena (climatic changes, geotectonic, seismicity, volcanism, diapirism) to such an extent that these could unacceptably impair the isolation capability of the overall disposal system[3].

Practically all of the territory of Armenia is situated in one of the most seismically active zones in the world. The magnitude of earthquakes ranges up to 7.1 with a focal depth, on average, of 10 kilometers. The average recurrence interval of large earthquakes (> 5.5) is about 30-40 years[4]. Therefore, it is unlikely that a location that meets IAEA criteria for siting a geologic disposal facility could be found in Armenia.

Even if a suitable location could be found, the cost for a geologic disposal facility in Armenia would be very high. Although no geologic disposal facilities have been completed to date, an OECD/NEA [5] expert group has developed cost estimates of 358-430 $US per Kg of heavy metal (kgHM) for such facilities based on design studies in Sweden, Spain, and Finland. However, these reference facilities are up to 25 times larger than would be required for ANPP SNF. Because a large portion of the costs for a geologic disposal facility are not related to size of the facility, the unit cost in Armenia for a similar design would be considerably higher. An estimated cost for a geologic disposal facility to hold the SNF from ANPP after a 2015 shutdown would be in the range of $500-700 million.

Transporting the SNF to another country, such as Russia, for final disposition is another option for disposal. Over the past ten years, there have been a number of proposals for international spent fuel storage and disposal. The most frequently cited is the Non-Proliferation Trust (NPT) Project, proposed in 1999, in which Russia would accept spent nuclear fuel from other countries for a fee of $1,500/KgHM. [6] The NPT forecast the cost for disposal of spent fuel at $400 per Kg; the surplus would be used to finance safeguards enhancements at Russian nuclear facilities and pensions for retired nuclear experts. Other proposals have fees as high as $2,000/KgHM. Bulgaria recently negotiated a fee of $620 per Kg for spent fuel from the Kozlodui plant. However, the spent fuel was never shipped due to lack of storage facilities at the Russian reprocessing plant and opposition from the Russian Regulatory Authority.

Transporting the SNF to another country is not feasible at this time. The fuel reprocessing facility in Russia is currently not operating and is not accepting any fuel for storage. The only usable rail line to Russia runs through Azerbaijan and is currently closed to Armenian traffic. However, these issues may be resolved within the next ten years. When the Russian disposal facility becomes operational and transportation routes are available, the current estimate for transportation costs and fees for disposal of spent fuel in Russia is between $600 to 1,500 per KgHM. This translates to a range of $143 - $358 million to dispose of the SNF from ANPP after a 2009 shutdown. Each additional year of operation will produce SNF with disposal cost of $7 - $17 million dollars.

3.2 INTERIM STORAGE

Following permanent shutdown of ANPP, the SNF will have to be stored for an interim period until a disposal path becomes available. There are several alternatives for interim storage. One alternative would be to continue the current approach utilizing a combination of wet and dry storage at ANPP until the SNF is sent of site for disposal. Soon after shutdown of the ANPP, the SNF cooling pools and associated systems would be isolated from the remainder of ANPP systems, creating a “spent fuel pool island” within the ANPP facility. This would allow the remainder of the ANPP systems to be permanently de-energized and deactivated, although decommissioning of the spent fuel pool island could not be completed until the SNF had been removed. This option has the advantage of having the lowest near term investment requirement of the options

considered. If SNF can be transported off site for disposal within 5 to 10 years after plant shutdown, additional dry storage facilities for long term interim storage would not be needed. However, continued maintenance and operation of both the wet and dry storage facilities over long term period is inefficient and ultimately has higher life-cycle costs than other options.

A second alternative is to expand the on site dry storage facility to provide long-term interim storage for SNF after ANPP shutdown. The existing dry storage technology is a horizontal storage module (HSM) design under license from the U.S. company Transnuclear. Each HSM holds one dry shielded canister, which has a capacity of 56 SNF elements. HSMs are designed to be cooled by natural air circulation, so no cooling or other support systems are required. The dry storage facility must be continuously guarded and periodically inspected as long as the fuel is present. In the US, dry storage casks of the same design as those used at ANPP are licensed for a period of 20 years with provisions for extending the license for another 20-40 years after thorough inspections. By these standards, the interim dry storage of SNF at ANPP could not be longer than 60 years.

Interim storage of the SNF in pool storage at the end of 2009 will require expansion of the on site dry storage facility by an additional 25 HSMs at an estimated cost of $24 million. Operation beyond 2009 will require addition of an average of 1.7 HSMs per year at a cost of $1.5 million, although this should be considered an operating cost. The costs for the expansion include the design, procurement, and construction of additional HSMs and enlargement of the security zone around the storage facility. The incremental annual cost for on-going security and maintenance of the dry spent fuel storage facility is relatively low. While this option has a significant upfront investment associated with the expansion, it has the advantage of allowing elimination of all nuclear safety systems within the ANPP and minimal annual operation and maintenance costs. Since dry storage has already been implemented at the ANPP site, expansion of the dry storage facility to include the remaining SNNF on site would be relatively straightforward from both a regulatory and technical capability perspective.

A third option for interim storage is the construction of a new spent nuclear fuel dry storage facility at a site within Armenia other than the ANPP site. Constructing a dry storage facility at another site within Armenia has a much higher capital cost, as well as significant transportation costs, as compared to expansion of the existing dry storage facility at the ANPP site.

4. PREVIOUS STUDIES OF ANPP DECOMMISSIONING

This section presents a discussion of previous studies of plans and costs for the decommissioning of ANPP and similar plants.

4.1 SUMMARY OF PREVIOUS STUDIES

There have been two previous studies of the decommissioning costs for ANPP. These studies are described in the following documents:

1. *Preparation of a Plan, Including Funding Policy, for the Decommissioning of the Armenian NPP*, TACIS Project EAR 9801, Task 4.1, May 2001[(7)]. This study was performed by SOGIN to evaluate the technical and economic factors related to the decommissioning on the ANPP. The study provides a summary of cost estimates for the SAFESTOR, SAFESTOR/Full-Staff, and DECON scenarios.
2. *Assessment of the Armenian NPP Decommissioning Costs*, TACIS Project EAR 9801, Task 4.2, May 2001[(8)]. This report presents the results of a detailed assessment of the decommissioning cost for the ANPP using the SAFESTOR scenario. These results are used in the summary report for Task 4.1.
3. *Preliminary Decommissioning Plan for the Armenian Nuclear Power Plant*, Draft Report, March 2001[(9)]. Pacific Northwest National Laboratory (PNNL) performed this study under contract to the US Department of Energy (DOE). The purpose of this study was to identify and evaluate the costs of feasible decommissioning options for the ANPP.
4. IAEA TECDOC-1322, *Decommissioning Costs of WWER-440 Nuclear Power Plants, Interim Report: Data Collection and Preliminary Evaluations,* November 2002[10)]. This report presents the results of a survey of decommissioning cost estimates from VVER-440 nuclear power plants in different countries including Armenia, Bulgaria, Czech Republic, Finland, Germany, Hungary, Russian Federation, Slovakia, and Ukraine. The cost estimates provided for Armenia are the same as those presented in the PNNL study.

The SOGIN study focused on a fairly detailed analysis of decommissioning of the ANPP using the SAFESTOR strategy. The study assumed a plant shutdown at the end of 2004, followed by nine years of work to prepare the plant for SAFESTOR. This work included moving the spent fuel from the reactor and fuel pools into dry storage containers. Following 36 years of SAFESTOR, the nuclear plant would be dismantled and all radioactive material removed from the sight during a 12-year period. The final phase is sight restoration that would require four years.

The SOGIN SAFESTOR decommissioning cost estimates were performed in 2000 using prices in 1999 Euros. SOGIN used the CALCOM-CORA software for performing the cost estimate. This code was developed based on German decommissioning experience. The SOGIN decommissioning cost estimate was based on ANPP data as much as possible. Where data were not available, extrapolations from other cost data for the Trino (a pressurized water nuclear plant in Italy) and Greifswald (a VVER 440/213 plant in Germany) decommissioning projects were used.

The SOGIN study uses the results of the SAFESTOR cost analysis to perform preliminary estimates of the DECON and SAFESTOR Full-Staff scenarios. The SAFESTOR Full-Staff scenario assumes a large portion of the ANPP operating staff would be retained for the first 15 years of the decommissioning, primarily to provide employment to these personnel. This Full-Staff case is more related to social policy than decommissioning and will not be reviewed further.

PNNL cost estimates were based on a plant shutdown at the end of 2009 and used prices in 1999 US dollars. At the time the estimates were prepared, the dollar and Euro were about equivalent. The PNNL decommissioning cost estimate study reviewed six scenarios:

1. DECON - the plant is decontaminated and dismantled within about 10 years after shutdown. Spent fuel is moved into dry storage containers and a radioactive waste disposal facility is constructed on sight to dispose of radioactive materials.
2. SAFESTOR/DECON 1 – the spent nuclear fuel in the spent fuel pools is moved into dry storage about 25 years after shutdown, requiring continued operation of many of the plant safety and auxiliary systems. Decontamination and dismantlement of the plant is then delayed for another 25 years. .
3. SAFESTOR/DECON 2 – spent nuclear fuel is moved into dry storage within five years after shutdown, allowing shutdown of all plant safety systems and most auxiliary systems. Most decontamination and dismantlement of plant systems is delayed for 50 years.
4. ENTOMB - the plant is decontaminated to the extent necessary and entombed in place within about 10 years after the plant is permanently shutdown. Spent fuel is moved into dry storage containers. Radioactive waste disposal is not required because the waste is entombed in the reactor building.
5. SAFSTOR/ENTOMB 1 - the spent nuclear fuel in the spent fuel pools is moved into dry storage about 25 years after permanent shutdown, requiring continued operation of many of the plant safety and auxiliary systems. Entombment of the plant is then delayed for another 25 years.
6. SAFSTOR/ENTOMB 2 - the spent nuclear fuel is moved into dry storage within four years after permanent shutdown, allowing shutdown of all plant safety systems and most auxiliary systems. Entombment of the plant is delayed for 50 years.

The SAFESTOR/DECON 1 and SAFSTOR/ENTOMB 1 scenarios both involve leaving spent fuel in the spent fuel pools and operating the spent fuel pools for about 25 years. This approach is considerably more costly than the others investigated and has potential safety problems if the spent fuel pool integrity is challenged. The only justification for this scenario would be if disposal of the spent fuel to another location were anticipated within the near future. Because there is currently no firm plan for disposal of the spent fuel from ANPP, these scenarios will not be reviewed further.

The model used by PNNL to calculate many of the decommissioning costs for this study is the Cost Estimating Computer Program (CECP), which was originally developed for the U.S. Nuclear Regulatory Commission to estimate the cost of decommissioning US light-water reactor power stations to the point of license termination. ANPP plant data were used in the calculations. To the extent practicable, PNNL adjusted the parameters of the CECP program to account for differences in the economic conditions in the US and Armenia including: the costs of labor, the cost of equipment and materials, the cost of structural materials, and labor productivity ratios. PNNL used conversion factors in the CECP to convert these parameters from U.S conditions to Armenian conditions.

4.2 COMPARISON OF PNNL AND SOGIN DECOMMISSIONING COST ESTIMATES

The results of the PNNL and SOGIN cost estimates for the various ANPP decommissioning scenarios are shown in table 1. All costs are in constant 1999 dollars. Without considering spent fuel disposition, the SOGIN estimates are about 2.4 times higher than the PNNL estimates for equivalent scenarios. For the SAFESTOR scenario,

the $300 million difference in the cost estimates (before contingency) can be attributed to differences in assumptions regarding project staffing and waste disposal fees. The SOGIN estimate assumes a much larger staff during the initial phases of the project than does the PNNL estimate. Also, SOGIN assumes that Armenian labor costs escalate 350 percent between plant shutdown and the dismantling phase of the project, reflecting an assumed growth in the Armenian economy during this 40-year period. Without labor cost escalation, the SOGIN estimate would be reduced by $76 million (before contingency). The PNNL study assumes no escalation in labor rates.

Table 1: Comparison of PNNL and SOGIN Decommissioning Cost Estimates for 2004 ANPP Shutdown (Millions of 1999 US Dollars)

	PNNL				SOGIN	
	DECON	SAFSTOR/ DECON 2	ENTOMB	SAFSTOR/ ENTOMB 2	DECON	SAFSTOR/ DECON
D&D Activities	91.8	133	75.9	117.1	375	448
Sight Restoration	20	20	20	20	25	34
Rad Waste Management	31.3	26.5	16.7	16.1		
Spent Fuel Management	20.4	20.4	20.4	20.4	20	18
Total	163.5	199.9	133	173.6	420	500
Contingency	40.9	50.0	33.3	43.4	84	100
Estimated Cost for Decommissioning	**204.4**	**249.9**	**166.3**	**217.0**	**504**	**600**
Spent Fuel Disposal	350-580	350-580	350-580	350-580	216	216
Total Costs	**554-784**	**600-830**	**516-746**	**567-797**	**720**	**816**

The cost for disposal of low and intermediate level radioactive waste is the other major difference in assumption between the two SAFESTOR estimates. Both studies assume about the same volume of waste requiring disposal, about 17.3 thousand cubic meters. SOGIN assumes that the waste would be sent to an unidentified off sight facility for a fee equivalent to European disposal fees. Total disposal fees included in the SOGINS SAFESTOR estimate are $117 million. PNNL assumes a radioactive waste disposal facility is constructed on the ANPP site for a cost of $10.3 million. Related to the assumption on waste disposal is the cost for packaging of low activity waste. The SOGIN estimate has a cost of $119 million for “investment” most of which is for containers for waste disposal. PNNL assumes relatively low cost drums will be used for low activity waste, with a total cost for containers of less than $10 million. Taken together, the cost associated with offsite waste disposal in the SOGIN estimate is about $220 million higher (before contingency) than the costs for onsite disposal assumed in the PNNL study.

After accounting for the differences in assumptions on labor cost escalation and waste disposal, the SOGIN and PNNL estimates of the SAFESTOR/DECON scenario produced similar values. The PNNL assumptions on waste disposal seem more appropriate for the situation in Armenia. Although, the suitability of the ANPP sight for construction of a low-level waste disposal facility must be verified through a comprehensive assessment, it would make little technical or economic sense to move radioactive waste materials away from this site to another site in Armenia. The SOGIN approach to escalation of labor costs seems arbitrary and conflicts with the use of constant dollars for all other costs. For these reasons, the PNNL estimate provides a better basis for further evaluation of decommissioning cost.

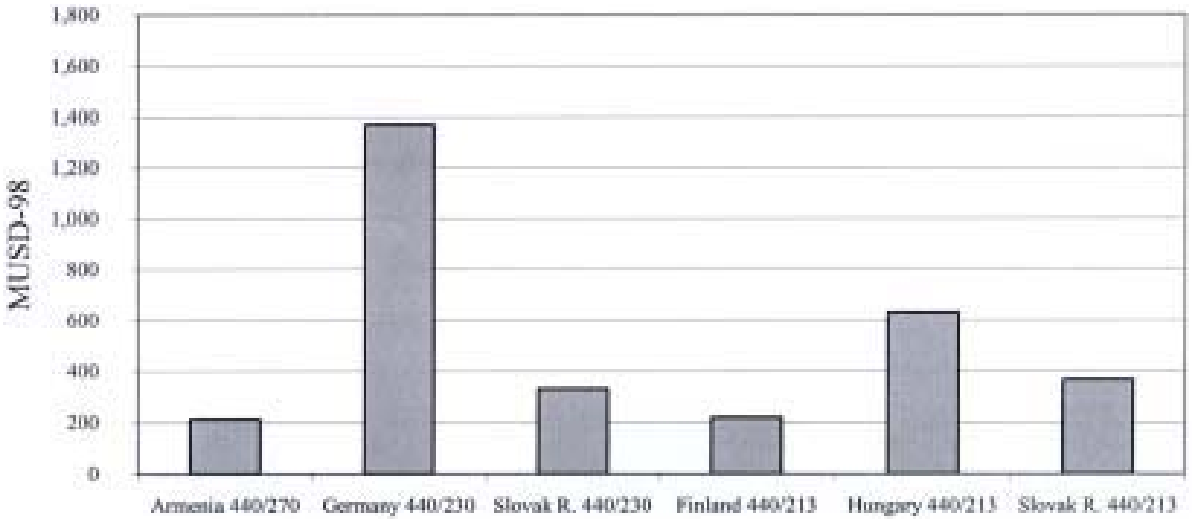
4.3 COMPARISON TO OTHER VVER440 DECOMMISSIONING ESTIMATES

IAEA TECDOC-1322, *Decommissioning Costs of WWER-440 Nuclear Power Plants, Interim Report: Data Collection and Preliminary Evaluations* [10], reports the results of an IAEA project to survey the decommissioning costs of VVER-440 nuclear power plants. The survey was performed by a questionnaire distributed among representatives of IAEA Member States operating VVER-440 NPPs or having such units in shutdown conditions or even in decommissioning stage. The questionnaire requested cost data for decommissioning a VVER-440 twin unit, organized in accordance with standardized cost elements.

A summary of the costs for the immediate dismantlement (DECON) option is shown in Figure 1. The total costs for the immediate decommissioning option vary from $213 million (Armenia) to $1,370 million (Germany). However, the large differences in cost estimates are mainly due to country and site specific conditions. The German estimate was determined as 44 percent of the total decommissioning cost for the five unit Greifswald sight. Major costs for post-operational and site support activities resulted from the unplanned plant shutdown, which caused these activities to require an excessively long time period before decommissioning could be started (about 5 years). Also contributing to the high cost for the German plant are relatively high German labor costs and European waste disposal fees.

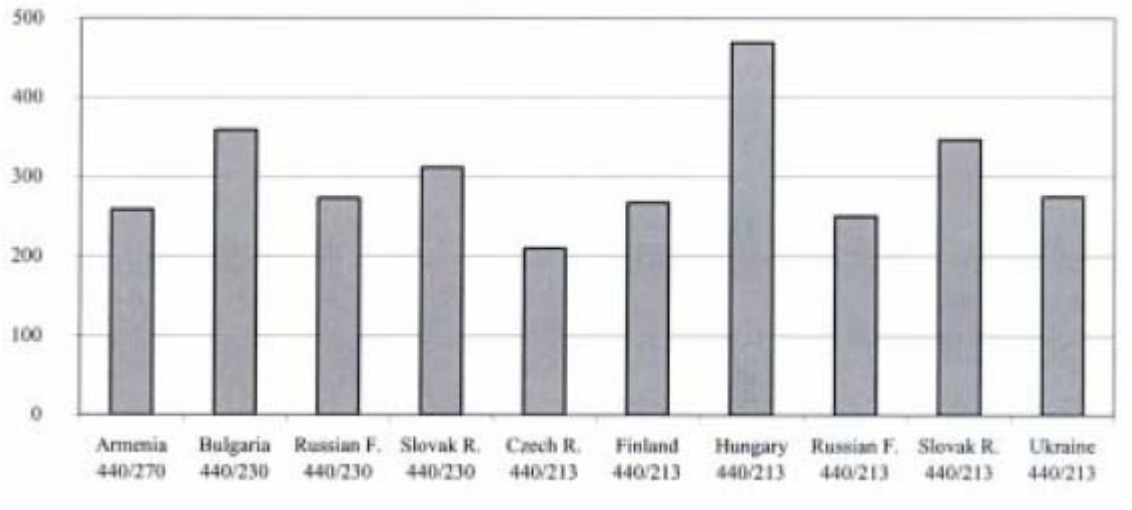
Among the other projects, the highest cost for immediate dismantlement is $632 million (Hungary). The Hungary cost estimate was developed as a portion of the cost for decommissioning the four unit Paks NPP. Because Hungary does not yet have any disposal facility available to accommodate the wastes from decommissioning, the costs included for disposal were based on disposal fees in European countries.

Figure 1: Summary of Total Decommissioning Costs for VVER-440 Immediate Dismantlement



period (70 years), the costs for the facility shutdown operations, and the disposal costs of decommissioning waste. The lower figure for the Czech plant is mainly due to the reduced scope considered when compared to the other plants in the study.

Figure 2: Summary of Total Decommissioning Costs for VVER-440 Safe Storage



The IAEA study concludes that VVER-440 decommissioning cost estimates that are currently available from different countries are not directly comparable. Large cost differences occur for several reasons:

- In some countries, certain cost factors are not yet well known.
- Some decommissioning plans are not completed and major decisions have not yet been made.
- There are significant differences in the scope of decommissioning activities and regulations.
- There are significant differences in approaches for radioactive waste disposal.

In comparing the Armenia cost estimate for immediate dismantlement to the other countries, it can be seen that the ANPP estimate is the lowest reported and is approximately 60 percent of the median of the six estimates. For the safe storage case, where the variance in estimates is not as large, the ANPP estimate is within 10 percent of the median of the ten estimates. However, as concluded in the IAEA study, direct comparisons with the other estimates are not very meaningful.

4.4 CONCLUSIONS ON PREVIOUS COST STUDIES

The previous ANPP decommissioning cost studies, prepared by PNNL and SOGIN, provide a reasonable basis for evaluating decommissioning strategies and establishing a decommissioning fund. Both organizations have experience in performing decommissioning cost studies and used widely accepted methods and calculation software. After accounting for the differences in assumptions on labor cost escalation and waste disposal, the SOGIN and PNNL estimates of the SAFESTOR/DECON scenario produced similar values. These results are also consistent with the range of decommissioning cost estimates for VVER 440 plants in other countries. The PNNL assumptions on waste disposal seem more appropriate to the situation in Armenia. For this reason, the PNNL decommissioning cost estimates were selected as the basis for the costs estimates of this study.

5. ADJUSTMENT TO PNNL DECOMMISSIONING ESTIMATES

SCIENTECH performed a detailed review of the cost elements of the various PNNL cost estimate scenarios. Summary descriptions of the PNNL decommissioning scenarios reviewed are presented in Annex A. The review was performed by developing cost estimates for the SAFESTOR and ENTOMB scenarios based on estimates recently prepared for a nuclear plant in the Midwestern US with two 1020 MWe pressurized water reactors. The reference plant estimates were scaled to the smaller size of the ANPP; utility staff labor rates were adjusted to match the Armenian staff labor rates of the PNNL study; and disposal fees were eliminated. The results of the reference plant estimates were compared to the cost elements of the PNNL estimates to identify areas for detailed analysis.

The first significant difference noted was in the level of effort for work planning and licensing during the Planning and Preparation period prior to shutdown. History has shown that the planning and preparation period not only requires a significant effort, but also is critical to providing a smooth transition from operation to decommissioning. Current SCIENTECH estimates assume that a specialized contractor, separate from the decommissioning contractor, will be brought on-site prior to shutdown and again prior to dismantlement to develop these plans and procedures. Some of the items included in work planning and licensing are the preparation of task specifications and work procedures; preparation of the emergency, quality assurance, and security plans; revisions to the Safety Analysis Report; and preparation of request for proposals for decommissioning contractor. In addition, licensing documents, such as a decommissioning plan and a license termination plan, will be required. While the regulatory requirements in Armenia are currently being defined, it is reasonable to assume that they will be similar to US and European requirements.

The PNNL study does not specifically identify any costs associated with planning and licensing. It does include costs for six Western contractors during the Planning and Preparation period. Experience shows that it will require at least 15 specialized contractors to support the work planning and licensing during the Planning and Preparation period. For this reason, $8 million was added (before contingency) to the costs for this period in each of the scenarios. This estimate is based on an additional 9 Western contractors during the Planning and Preparation period at the same average labor rates that are used in the PNNL estimate. The SAFESTOR scenarios will require additional planning effort to transition from the Safe Storage to the Dismantlement or Entombment period, which is not reflected in the PNNL estimate. For this reason, $4 million per year was added (before contingency) to the costs in the final three years of the Safe Storage periods. This estimate is based on additional Western contractors at the same average labor rates that are used in the PNNL estimate.

The largest difference in cost is associated with the assumed Contractor staff during period 2 (Defuel and Deactivate) and period 5 (Dismantlement). Current industry practice in the US is to utilize an experienced decommissioning contractor staff to supervise the use of specialty tools and other dismantling activities. Without this expert staff, there will be a significant loss of time and resources due to the learning curve associated with a change from operation to decommissioning. This is especially true after an extended dormancy period prior to dismantling, such as that envisioned in the SAFSTOR scenarios, when the current ANPP staff will not be available.

The PNNL estimate assumes seven Western contract workers during the Defuel and Deactivate and Dismantlement periods. Experience shows that it will require 25 to 30 specialized contractors to support the deactivation and dismantling work. For this reason, $8 million was added to the costs for Deactivation in each of the scenarios; $13 million for

Dismantling in the DECON and ENTOMB scenarios; and $18 million for Dismantling in the SAFESTOR scenarios. These additional costs do not include contingency. This estimate is based on the cost for additional Western contractors at the same average labor rates that are used in the PNNL estimate.

A third difference in cost estimates is for costs associated with the post-shutdown transfer of spent fuel to dry storage. The PNNL estimate assumes that, for a 2009 shutdown, there will be 1,897 spent fuel assemblies requiring dry storage in addition to the dry storage already in place. The estimate includes approximately $27 million, without contingency, to design, procure and construct 34 additional dry storage modules. At the end of 2004, there were actually 545 assemblies in the spent fuel pools, with an additional 349 assemblies in the unit 2 core. With a discharge rate of 96 assemblies per year for the next five years and a full core discharge in 2010, new dry storage will be required for only 1,374 assemblies after shutdown. This will require the purchase of 25 additional storage modules. This represents a cost reduction of approximately $8 million (before contingency) from the PNNL 2009 estimate for Spent Fuel Management.

If ANPP operates until 2015 there will be additional spent fuel assemblies on-site at shutdown. However, due to the spent fuel pool capacity limitations these assemblies will be transferred to dry storage prior to shutdown. These costs are considered as operating costs and are not included in this decommissioning cost analysis.

PNNL estimated a range of $450 - $750 million for spent fuel disposal. The bases for these estimates are not discussed in the draft report. Based on the spent fuel disposal fees of $600 to $1,500 per KgHM, the cost for disposal of the 1,986 fuel assemblies at ANPP at the end of 2009 would be between $143 and $358 million.

The adjusted decommissioning cost for each of the decommissioning scenarios for ANPP shutdown at the end of 2009 is shown in table 2. Schedules of decommissioning cost by year for each of the decommissioning scenarios are provided in Annex B. These schedules do not include the cost of spent fuel disposition because the amount and timing of these costs is not known.

Table 2: Adjusted PNNL Decommissioning Cost Estimates for 2009 ANPP Shutdown (Millions of 1999 US Dollars)

	DECON	SAFSTOR/ DECON 2	ENTOMB	SAFSTOR/ ENTOMB 2
D&D Activities	120.8	179	104.9	163.1
Sight Restoration	20	20	20	20
Rad Waste Management	31.3	26.5	16.7	16.1
Spent Fuel Management	19	19	19	19
Total	191.1	244.5	160.6	218.2
Contingency (25%)	47.775	61.125	40.15	54.55
Estimated Cost for Decommissioning	**238.875**	**305.625**	**200.75**	**272.75**
Spent Fuel Disposal	143-358	143-358	143-358	143-358
Total Costs	**382-597**	**449-664**	**344-558**	**416-631**

In conclusion, the detailed review of the PNNL estimates for SAFESTOR and ENTOMB scenarios, based on comparisons to estimates recently prepared for a pressurized water

reactor plant in the US, identified some areas in which adjustments are recommended. These areas were primarily related to the need for an increased level of support from decommissioning experts during the planning and dismantlement phases of decommissioning and to more recent information on SNF inventory. The recommended adjustments increase the estimated decommissioning costs by less than 20 percent, within the contingency band of 25 percent. These differences do not reflect any defect in the PNNL estimate, which was prepared with the data available at the time. Rather, they demonstrate the need to develop a very detailed plan, schedule, and cost estimate for the selected decommissioning scenario using plant specific information.

The cost of final disposal of SNF, while not usually included in decommissioning costs, represents a substantial future cost for ANPP that is currently unfunded. Returning the SNF to Russia for reprocessing is the most feasible disposal option. However, this option is not currently available and the timing and cost cannot be estimated accurately at this time. The cost for disposal of the current spent fuel inventory is potentially larger than the plant's decommissioning cost.

6. FUNDING OF DECOMMISSIONING COSTS

In most countries, the responsibility for funding of decommissioning of nuclear facilities lies with the owner of the facility. The way in which such decommissioning funds are accumulated and managed varies from country to country. In general, these funds are created from business revenues. In almost all cases, the size of the necessary decommissioning fund is reviewed on a regular basis, generally between 1 and 5 years. The calculated sum is accumulated year by year over the planned lifetime of the facility. Some countries allow operators to accumulate and manage their own funds, under appropriate supervision, and in other countries the funds are collected from the operators and managed by separate, independent, bodies. For example, in Finland, a State Nuclear Waste Management Fund, under the Ministry of Trade and Industry, collects, holds and invests the funds. In Switzerland and Hungary, however, the fund is collected and administered directly by the national government.

The Armenian government has adopted an amendment to the Law on the Safe Use of Nuclear Energy for Peaceful Purposes. This amendment reaffirms sections of the Republic of Armenia Energy Law that requires a portion of the ANPP electricity sales be set aside to fund plant safety, security, and other upgrades as well as decommissioning. Charters and decrees to define the amounts to be collected for decommissioning and the process for collecting and managing the funds are currently being developed.

The following sections discuss the establishment of a decommissioning fund sufficient to ensure decommissioning of ANPP.

6.1 PRESENT VALUE OF DECOMMISSIONING COSTS

The decommissioning cost estimates described in the previous sections were calculated in constant 1999 dollars. Because the decommissioning work will not start for several years and will be performed over a period of many years in the future, it is necessary to adjust these cost estimates to account for escalation and for the present value of money. The escalation accounts for inflation in labor, materials and other costs from 1999 until the time the costs are actually incurred. To determine the amount of money needed for decommissioning at the time of ANPP shutdown, the escalated value of future decommissioning costs must be discounted to account for interest earned on decommissioning funds between the time of shutdown and the time the costs are actually incurred.

The escalated and present value of decommissioning costs were calculated using the schedules of decommissioning cost by year for each of the decommissioning scenarios as presented in Annex B. The cost for spent fuel disposition was not included in these calculations because the amount and timing of these costs is not known. The assumptions used for calculation is based on an escalation rate of one percent per year for decommissioning costs and an interest rate of four percent per year for a low risk investment of decommissioning funds. The results of the escalated present value calculations of decommissioning costs for plant shutdown at the end of 2009, 2015, and 2035 are shown in tables 3, 4, and 5 respectively.

Table 3: 2010 Present Value of Escalated Decommissioning Cost Estimates for 2009 ANPP Shutdown (Millions of US Dollars)

Decommissioning Scenario	Cost in 1999 $	Escalated Cost	2010 Present Value
DECON	238.8	280.8	227.4
SAFSTOR/ DECON 2	305.7	454.8	173.6
ENTOMB	200.7	234.4	194.8
SAFESTOR/ENTOMB 2	272.7	421.3	165.3

Table 4: 2016 Present Value of Escalated Decommissioning Cost Estimates for 2015 ANPP Shutdown (Millions of US Dollars)

Decommissioning Scenario	Cost in 1999 $	Escalated Cost	2016 Present Value
DECON	238.8	298.1	241.4
SAFSTOR/ DECON 2	290.7	513.8	186.9
ENTOMB	200.7	248.8	206.8
SAFESTOR/ENTOMB 2	272.7	446.8	176.4

Table 5: 2036 Present Value of Escalated Decommissioning Cost Estimates for 2035 ANPP Shutdown (Millions of US Dollars)

Decommissioning Scenario	Cost in 1999 $	Escalated Cost	2036 Present Value
DECON	238.8	363.8	152.0
SAFSTOR/ DECON 2	290.7	627.0	122.1
ENTOMB	200.7	303.6	130.8
SAFESTOR/ENTOMB 2	272.7	545.2	114.3

The present value figure represents the amount of money that should be on hand at the time of plant shutdown to finance future decommissioning costs. The results show that although the scenarios involving SAFESTOR have a higher total cost, they have a lower present value because a large portion of the cost is deferred 40 years into the future.

It should be noted that the escalated present value results shown above are very sensitive to the difference between the assumed escalation and discount rates. For Armenia, it may be anticipated that escalation in construction labor costs over the next 40 years will be higher than the general rate of inflation and therefore the difference between the escalation rate and the discount rate will be small. The SOGIN decommissioning cost study, described in section 3, assumed an average labor escalation rate of 3.2 percent over the next 40 years because of the currently very low wage rates in Armenia. This assumption increases the relative cost of the SAFSTOR scenarios in which a large portion of the cost is deferred 40 years. To illustrate this effect, table 6 presents the results of the escalated present value calculations of decommissioning costs for plant shutdown at the end of 2015 assuming a three percent escalation rate and four percent discount rate. Based on these assumptions, the scenarios involving SAFESTOR will have a higher present value as well as a higher total cost. The sensitivity of decommissioning costs to price escalation is a significant risk factor for the scenarios involving SAFESTOR.

Table 6: 2016 Present Value of Decommissioning Cost Estimates for 2015 ANPP Shutdown with High Escalation (Millions of US Dollars)

Decommissioning Scenario	Cost in 1999 $	Escalated Cost	2016 Present Value
DECON	238.8	464.4	371.2
SAFSTOR/ DECON 2	290.7	1699.4	379.7
ENTOMB	200.7	381.9	313.9
SAFESTOR/ENTOMB 2	272.7	1409.6	346.6

As discussed above, the cost and timing of SNF disposition costs cannot be determined at this time. The current estimate for transportation costs and fees for disposal of the SNF from ANPP after a 2009 shutdown is between $143 - $358 million. Each additional year of operation will produce SNF with disposal cost of $7 - $17 million dollars. The present value of these costs depends on how long the SNF is maintained on ANPP site prior to disposal and on the rate of escalation in disposal fees. It should be noted that these are rough estimates and are fairly sensitive to the assumed time frame for fuel disposal as well as the potential escalation in disposal fees. There is the possibility that the disposal fees may escalate substantially if disposal capacity is limited and there is a large international demand. It is also possible that disposal could occur shortly after plant shutdown, which would require a much higher present value.

6.2 DECOMMISSIONING FUNDING ALTERNATIVES

There are a number of ways to fund the decommissioning costs for ANPP. A commonly used method is an electricity rate surcharge on the Kwh tariff on nuclear plant generation to collect the needed decommissioning funds over the remaining life of the plant. The period for this surcharge could also extend through the decommissioning period. These funds would need to be placed into an account with the sole purpose of paying for decommissioning. The funds could be conservatively invested and the earnings from the investments used to help pay for the decommissioning when it occurs.

To determine the amount of surcharge needed to fund decommissioning, it was assumed that the surcharge would begin in 2006 and extending through 10 years after plant shutdown. The 10 year after shutdown period corresponds to the duration of the ENTOMB or DECON scenarios. It is assumed that the funds collected from the surcharge are invested at an interest rate of four percent per year. The estimates of the annual surcharge needed to fund each of the decommissioning scenarios for plant shutdown in 2009, 2015, and 2035 are shown in table 7.

Table 7: Surcharge Beginning in 2006 to Fund ANPP Decommissioning and Existing Spent Fuel Disposal Cost

Decommissioning Scenario	2009 Shutdown	2015 Shutdown	2035 Shutdown
	Annual Surcharge ($Million)	Annual Surcharge ($Million)	Annual Surcharge ($Million)
DECON	17.95	11.70	4.43
SAFSTOR/ DECON 2	13.95	9.09	3.44
ENTOMB	15.38	10.03	3.79
SAFESTOR/ENTOMB 2	13.09	8.58	3.25

The tariff established for ANPP in 2003, excluding tax, was based on total revenue from electric sales of 13.5 billion dram, equivalent to $27 million, which included allowance of about $0.2 million for decommissioning. Addition of the surcharge for decommissioning based on 2009 shutdown would increase the price of ANPP generation by 50 to 70

percent. The surcharges would substantially increase the price of electricity from the ANPP.

The collection of decommissioning funds through a special surcharge on a nuclear plant's electricity sales is based on the principal that the users of the electricity should pay for the eventual decommissioning of the plant that produces it. Application of a surcharge on ANPP generation to collect the full decommissioning cost over the plant's remaining life to 2015 somewhat distorts this principal. Almost half of the decommissioning cost is attributable to Unit 1, which supplies no electricity to current users. For unit 2, one third of the useful life of the plant was consumed prior to 1989. It could be argued that the obligation for funding the decommissioning of unit 1, and one third of unit 2, belongs to the owner of the plant up until 1989, the former Soviet Union. Under this concept, current consumers of electricity should pay only about one third of the decommissioning surcharge calculated above. The remainder of the decommissioning cost would be raised by the Armenia Government through negotiations with Russia and other countries of the former Soviet Union that benefited from the electricity generated during that time. This argument does not apply to spent fuel disposal because all of the spent fuel to be disposed has been generated since 1995.

An alternative to putting a surcharge on ANPP generation would be to put a surcharge on all electricity consumed in Armenia. Based on shutdown in 2015, the surcharge for decommissioning would increase the average electric rates by about seven percent. It is recommended that the application of the surcharge to total consumption for a period of ten years after shutdown be used as an initial basis to establish decommissioning funding surcharges.

To estimate the funding required to pay for future disposition of spent fuel, several scenarios were investigated. The first three scenarios assume that the SNF would be removed from the ANPP site for disposal within 6 years after plant shutdown in 2009, 2015, or 2035 respectively. A fourth scenario assumes the ANPP is shutdown in 2009 but the SNF is removed in 2060, at the end of the design life of the existing HSM dry storage modules. A fifth scenario assumes the ANPP is shutdown in 2015 and that the SNF is disposed of in 2080, the end of the longest decommissioning scenario and 80 years of service for the existing dry storage containers. For each scenario, the amount of fuel to be dispositioned is the 1,506 elements in storage at the end of 2004 plus 96 elements for each year of operation after 2004.

Each scenario assumes the SNF is transported to Russia for disposal. Although there is currently no facility available for disposal of spent fuel in Russian, the cost for transportation and fuel disposal fees is estimated at between $600 to $1,500/KgHM. A value of $1,000/KgHM in 2004 dollars, representing the middle of this range, was used for each of the scenarios. In addition to uncertainty in current disposal costs, the possible rate of escalation in SNF disposal costs is uncertain. For this reason, a range of escalation rates from 0 to 4 percent was considered in each scenario.

For each scenario, it is assumed that funding for SNF disposal is collected through a surcharge on electrical generation during the period 2006 through 10 years after shutdown. It is assumed that the funds collected from the surcharge are invested at an interest rate of four percent per year. The estimated annual surcharges required to fund SNF disposal under each of the scenarios investigated are shown in table 8.

Table 8: Annual surcharge from 2006 to 10 Years after ANPP Shutdown to Fund Spent Fuel Disposal

Escalation Rate for SNF Disposal Costs	SNF Disposal Scenario				
	Disposal Date: 2015	Disposal Date: 2021	Disposal Date: 2041	Disposal Date: 2060	Disposal Date: 2080
	Annual Surcharge ($Million)	Annual Surcharge ($Million)	Annual Surcharge ($Million)	Annual Surcharge ($Million)	Annual Surcharge ($Million)
0	13.03	10.56	5.965	3.35	1.68
2 %	16.6	15.21	12.85	8.87	6.035
4 %	20.94	21.6	26.78	25.05	24.92

For these scenarios, the annual surcharge to fund SNF disposal range from $1.7 to 27 million. These results demonstrate the sensitivity of the cost for spent fuel disposal to assumptions on the timing and escalation of disposal fees. The scenarios involving delaying disposal by extended interim storage onsite have the benefit of allowing disposal funds to accumulate through investment return but also have greater financial risk if disposal fees escalate. Determining the appropriate surcharge for SNF disposal will require defining a disposal plan.

7. CONSIDERATIONS FOR SELECTION OF A DECOMMISSIONING STRATEGY

Selection of a decommissioning strategy involves consideration of a number of criteria. The issues to be considered include the following:

- Timing of funds available for decommissioning work
- Location of a repository for disposal of radioactive waste
- Availability of skilled labor
- Alternative uses for the site
- Method and timing of disposal of SNF
- Legal and regulatory requirements
- Political and social constraints
- Results of Safety and Environmental Assessments

The ENTOMB scenario should be carefully considered as an approach for decommissioning of ANPP. ENTOMB is the lowest cost decommissioning approach on a total cost basis. Because it can be completed on the shortest schedule, the ENTOMB scenario has the lowest financial risk. The total cost for the SAFESTOR scenarios could be much higher than the estimates discussed above if there is significant labor cost escalation in Armenia. Based on shutdown in 2015 and collection of decommissioning costs from a tariff on total electric sales from 2006 through 2026, the ENTOMB scenario could be funded by a 10 percent surcharge on domestic electricity consumption. This surcharge, while significant, is not substantial. For shutdown in 2009, any of the decommissioning scenarios would probably require obtaining a portion of decommissioning costs from foreign donors to make it affordable.

Because of land transportation limitations through countries neighboring Armenia, it is not currently feasible to transport large volumes of radioactive waste to another country for disposal. Although there is an existing low-level waste storage facility located near the plant, it does not have the capacity to accept the decommissioning waste from DECON of ANPP. It would have to be expanded substantially to allow disposal of the decommissioning waste or a new disposal facility would have to be constructed. The cost and licensing of a new disposal facility makes this solution problematic. The ENTOMB scenario has the benefit of using the ANPP reactor buildings as the final disposal vault for the radioactive waste, eliminating the need for new radioactive waste disposal facilities. The suitability of the reactor building and surrounding area as a permanent repository would need to be confirmed through a detailed assessment. However, the existing buildings appear to have much more robust structures for the containment of radioactive waste than the typical low-level waste disposal facility.

If there were a need to return the ANPP site to “green field” condition for an alternative use, the ENTOMB strategy would not be appropriate. However, the most likely alternative use of the ANPP site is for construction of another power plant that could use the electrical, transportation, and water infrastructure of the ANPP. The site was originally designed for four nuclear units, so leaving the ANPP reactor buildings as an entombment site should not preclude use of the site for a new fossil or nuclear power plant.

A potential disadvantage of the ENTOMB approach is that it will require continued security, monitoring, and regulatory control over the site for an indefinite period. However, until final disposal of the SNF, security, monitoring, and regulatory control of the SNF storage facilities at the ANPP site will be required. During this period, the incremental costs related to ENTOMB surveillance are minimal.

The decommissioning of the ANPP must be performed under the legal and regulatory requirements of Armenia, which are currently being developed. Until this legal framework is in place, the specific criteria that must be met by any decommissioning scenario will not be known. However, it can be anticipated that Armenian regulations will be consistent with safety standards and guidelines provided by IAEA and NRC. IAEA standards for near surface radioactive disposal include requirements for detailed safety assessment to evaluate the performance of a disposal system and its potential radiological effects on human health and the environment [(11) (12) (26)]. NRC has similar, though more detailed requirements that are described in references [(21) (22) (23) (24) (25)]. These standards would apply to the entombment structure as well as to any radioactive waste disposal facility constructed for the DECON scenario. Assuming the safety assessment demonstrates the suitability of entombment as a long-term confinement for radioactive waste, the ENTOMB approach would be consistent with future Armenian regulations. One important aspect of international standards for decommissioning activities is the criteria for maintaining radiation exposure “as low as reasonably achievable” (ALARA). From this standpoint, the ENTOMB scenario is preferred over DECON because expected radiation exposure to workers and the public would be lower.

There are a number of political and social issues associated with selection of a decommissioning strategy. An important social issue is the impact of the decommissioning strategy on the local work force. As mentioned above, the immediate ENTOMB scenario provides for better utilization of the existing work force than does the SAFESTOR scenario. Another potential social issue is the public acceptability of a radioactive waste disposal facility at a particular site. Public acceptance of any decommissioning strategy must be determined through a managed program of communications with stakeholder groups. However, it could be reasonably assumed that waste disposal by entombment of the existing nuclear facility would be more acceptable to the public than creation of a new radioactive waste facility that would be required for the DECON scenario.

An important benefit of the immediate DECON or ENTOMB scenarios as compared to a SAFESTOR scenarios is that they would employ a significant portion of the current ANPP skilled workforce for several years after shutdown. This would provide some stability for the ANPP operating staff during the final years of plant operation and ensure that the nuclear trained workforce, familiar with the plant design, will be available for the decommissioning work. In the SAFESTOR approach, much of the dismantling work is deferred for 50 years, at which time there may not be a nuclear experienced local work force available.

The SAFESTOR approach has an advantage in that there is some reduction in worker radiation exposure and quantity of radioactive waste. However, changes in legislation and regulatory requirements during SAFESTOR period may make dismantlement or entombment work more difficult. Also, ANPP will require maintenance, security, and regulatory control during the SAFESTOR period.

Assuming low rate of cost escalation over next 50 years, SAFESTOR scenarios have lower present value because a large portion of the cost is deferred into the future. However, SAFESTOR scenarios have greater financial risk if construction costs escalate more than the general rate of inflation.

In the case of Armenia, an important political consideration may be the reaction of potential foreign aid donors to the selected decommissioning scenario. On-site radioactive waste disposal, either entombment or in on-site disposal facilities, has not been broadly practiced by IAEA Member States as a decommissioning strategy. However, some research reactors and other nuclear facilities have been disposed of by

entombment in the US and other countries and on-site disposal is being planned in others. Recent NRC and IAEA studies [(14) (17) (20)] consider on-site disposal on grounds of cost reduction, simplicity of operation, reduction of occupational radiation exposure, and sometimes technical expediency. In this context, selection of the ENTOMB scenario, supported by a thorough and well documented performance assessment, should be as acceptable to international donors as a DECON approach. However, scenarios involving SAFESTOR are likely to be less attractive to foreign aid donors because of the long time frame for completion and the difficulty in committing aid/ funds 50 or more years into the future.

8. STRATEGIC PLAN FOR DECOMMISSIONING

Outlines of the plan and schedule for the phases and major tasks to be accomplished during each of the scenarios for decommissioning of ANPP are described in the PNNL report[9] and are summarized in Annex A. The objective of this section is to identify the elements and schedule of a strategic plan for preparing for ANPP decommissioning. Because the date for shutdown of ANPP has not been established, the schedule for most of the elements of the strategic plan is presented in terms of years prior to shutdown.

Establish Decommissioning Funding Program

The Armenian government has adopted an amendment to the Law on the Safe Use of Nuclear Energy for Peaceful Purposes. This amendment reaffirms sections of the Republic of Armenia Energy Law that requires a portion of the ANPP electricity sales be set aside to fund plant safety, security, and other upgrades as well as decommissioning. Charters and decrees to define the amounts to be collected for decommissioning and the process for collecting and managing the funds are currently being developed.

As discussed above, collection of decommissioning funds through a surcharge on total electric consumption and extending the collection period through decommissioning may be the preferred approach to minimize impact on consumer rates. The cost estimates discussed in this report provide sufficient basis for establishing initial tariff/ rate until more detailed decommissioning plans and cost estimates are available. Because the remaining life of the plant is relatively short, implementation of the surcharge in 2006 is necessary to ensure sufficient funds are collected prior to shutdown to accomplish post shutdown safety, security, and decommissioning activities.

Establish Legal and Regulatory Framework for Decommissioning

The ANRA is in the process of developing the legal and regulatory framework within which decommissioning will be carried out. The legal framework should clearly identify and establish responsibilities for organizations involved in the different steps of decommissioning, spent fuel, and radioactive waste management. While the current ANPP operating organization has responsibility under the operating license, responsibilities must be legally established for the post shutdown activities. If long-term institutional control of the site is deemed necessary, responsibility for carrying out those institutional controls must be legally assigned.

The ANRA is currently preparing its strategic plan for developing decommissioning regulations and establishing regulatory processes. This plan should include the following topics:

- Identification of fundamental safety principals for decommissioning.
- Approach to resolving safety and significant regulatory issues including radiological safety criteria, release limits, radioactive waste classification, waste disposal, quality assurance, security, and emergency planning.
- Specification of a process for transition form operating to decommissioning licensing.
- Format and content requirement for licensee submittals.
- Establishment of processes and criteria for review of license submittals.
- Establishment of processes for assessment, inspection, and enforcement of decommissioning, spent fuel, and waste management activities.
- Measures to ensure transparency and public communication.

ANRA should develop an implementation schedule for the elements of the strategic plan. Top priority should be given to establishing the radiological safety criteria, limits, and classifications needed as input to the safety assessment of radioactive waste storage facility and entombment structure.

Establish Decommissioning Project Team.

ANPP has established the nucleus of a project team to plan for the transition to decommissioning. This team should be expanded at least ten years in advance of the final planned shutdown. The technical and safety expertise of the team should include knowledge of plant systems, spent fuel and waste management, plant history, licensing and other decommissioning aspects. Typical objectives of the project team could include:

- Development of decommissioning plans
- Cost estimate verifications
- Safety Assessments
- Preparation of contractor work scope and bid documents
- Spent fuel management options
- Waste management plans
- Preparation of safety documentation,
- Interaction with stakeholders,
- Plant system reconfiguration and retirement
- Identification and management of records

The need for specialized training and analysis tools for the project team should be identified as early as possible to allow time for conducting the training and obtaining the tools.

Safety Assessment of ENTOMB and Radioactive Waste Storage Facility

An important consideration in the decommissioning of the ANPP is whether the ANPP site will be used as the final disposal site for radioactive waste. In conjunction with ANRA, ANPP should perform an initial safety assessment, following IAEA [(11) (12) (13) (26)] and NRC [21) (22) (23) (24) (25)] guidelines to determine the acceptability of a Radioactive Waste Storage Facility and ANPP reactor buildings as well as the surrounding environment at the ANPP site as barriers to migration of radioactivity over an extended period. This initial safety assessment will be updated later when more detailed plans are available to identify all radiological and non-radiological hazards involved in the proposed decommissioning Activities. The final safety assessment should identify the protective measures necessary to ensure the safety of the workers, the public and the environment during all phases of decommissioning.

A survey of radiological and non-radiological hazards is an important input for the safety assessment and for implementing a safe approach during the work. The objective of the characterization of radiological and chemically hazardous materials is to provide a reliable database on the quantity, types, distribution, and physical and chemical states of these materials. This should include contaminated land. Characterization includes reviewing existing data and calculations, taking measurements, sampling, analysis and undertaking of further calculations as needed. A characterization report should be prepared which documents the information and data obtained during the characterization process.

Another important part of the safety assessment is a performance assessment of the engineered and natural barriers that contain the radioactive material and prevent radiation exposure to the public. Radioactive waste disposal facility performance assessment is a

systematic analysis that addresses what can happen, how likely it is to happen, and what are the resulting impacts. The same type of performance assessment is applied to the case of entombment of waste in the reactor building as to construction of a new or expanded waste disposal facility. The essential elements of a performance assessment for a radioactive waste disposal site are:

- a description of the site and engineered system;
- an understanding of events likely to effect long-term facility performance;
- a description of processes controlling the movement of radionuclides from disposal containers to the general environment;
- a computation of doses to members of the general population; and
- an evaluation of uncertainties in the computational results.

Performance assessment establishes a record to support the technical basis and written documentation of model assumptions and data needed for a successful compliance demonstration. A performance assessment of the wastes in reactor building as an entombment structure should be performed as soon as possible to determine the feasibility of the ENTOMB decommissioning strategy. The data and methods of this entombment performance assessment could then be used in the performance assessment of a new or expanded waste disposal facility.

The initial safety assessment should be completed no later than eight years in advance of plant shutdown to allow time for identification and evaluation of alternative sites for radioactive waste disposal within Armenia in the event that the ANPP site is found to be unsuitable.

Define SNF Disposal Plan

Transporting the SNF to another country for disposal is the most likely solution to SNF disposal. Although this option is not feasible at this time, the issues preventing it may be resolved within the next ten years. The Armenian government must begin immediately to define the long term plans and schedule for disposal of the SNF. These plans will establish a basis for determining the appropriate surcharge for SNF disposal as well as providing necessary input to the ANPP decommissioning plan.

Prepare Decommissioning Plan

A detailed decommissioning plan for the ENTOMB approach should be developed by ANPP. Even if the shutdown of ANPP is not scheduled until 2015, this plan should be started now in order to develop the framework for regulatory decisions and as a basis for periodic updates of the cost estimate. In the event the ANPP must shutdown sooner than 2015, having the decommissioning plan in development stage will provide the means to effectively implement decommissioning activities, savings millions of dollars. This plan will also be useful in support of aid requests from foreign donor organizations.

Guidelines for contents and methods for decommissioning plans are provided in IAEA guidelines[13]. These guidelines identify the following topics to be considered for the decommissioning plan:

- a description of the nuclear reactor, the site and the surrounding area that could affect, and be affected by, decommissioning;

- the life history of the nuclear reactor, reasons for taking it out of service, and the planned use of the nuclear installation and the site during and after decommissioning;
- a description of the legal and regulatory framework within which decommissioning will be carried out;
- explicit requirements for appropriate radiological criteria for guiding decommissioning;
- a description of the proposed decommissioning activities, including a time schedule;
- the rationale for the preferred decommissioning option, if selected;
- safety assessments and environmental impact assessments, including the radiological and non-radiological hazards to workers, the public and the environment;
- this will include a description of the proposed radiation protection procedures to be used during decommissioning;
- a description of the proposed environmental monitoring program to be implemented during decommissioning;
- a description of the experience, resources, responsibilities and structure of the decommissioning organization, including the technical qualification/skills of the staff;
- an assessment of the availability of special services, engineering and decommissioning techniques required, including any decontamination, dismantling and cutting technology as well as remotely operated equipment needed to complete decommissioning safely;
- a description of the quality assurance program;
- an assessment of the amount, type and location of residual radioactive and hazardous non-radioactive materials in the nuclear reactor installation, including calculation methods and measurements used to determine the inventory of each;
- a description of the waste management practices, including items such as:
  - identification and characterization of sources, types and volumes of waste;
  - criteria for segregating materials;
  - proposed treatment, conditioning, transport, storage and disposal methods;
  - the potential to reuse and recycle materials, and related criteria; and
  - anticipated discharges of radioactive and hazardous non-radioactive materials to the environment;
- a description of other applicable important technical and administrative considerations such as safeguards, physical security arrangements and details of emergency preparedness;
- a description of the monitoring program, equipment and methods to be used to verify that the site will comply with the release criteria;
- details of the estimated cost of decommissioning, including waste management, and the source of funds required to carry out the work; and
- a provision for performing a final confirmatory radiological survey at the end of decommissioning.

The schedule for submission, review, and approval of the decommissioning plan will probably be defined by the ANRA decommissioning licensing process that is under development. However, because of the comprehensive nature of this plan and the need

for thorough review by ANRA, the decommissioning plan should be completed at least two years prior to planned shutdown.

Although it is included in the decommissioning plan, the organization and human resource plans have particular importance in maintaining the effectiveness of the operating organization during the years prior to plant shutdown. For this reason, preliminary versions of these plans should be developed early so they may be finalized and released shortly after the plant shutdown date is announced. Early planning with regard to the timing of final shutdown and the selected decommissioning strategy plays a major role in facilitating the management of personnel relocation and the retention of key staff.

In preparing these plans, a number of basic points need to be addressed and decisions made concerning the following:

- The required decommissioning organization,
- A staff reduction profile,
- The use of operating staff to undertake decommissioning project tasks,
- Policies for choosing which work will be contracted

The organizational structure to be employed during decommissioning should be described in the organization plan in such a way that there is a clear delineation of authorities and responsibilities amongst the various units.

The staff reduction profile will depend on the numbers, qualifications and experience of the personnel needed for the actual work to be carried out. Having established such a profile, commitments can then be made to staff regarding the length of their remaining employment and the implementation of staff reduction measures can be monitored.

Retaining a large number of operating staff will inevitably mean that they undertake decommissioning tasks. With some training, the operating staff can generally be used in the following areas:

- safety requirements of the license;
- radiation protection;
- familiarity with the reactor systems;
- engineering support (e.g. physics, instrumentation, chemical, civil, electrical and mechanical engineering);
- quality assurance and quality control;
- waste management;
- physical protection; and
- project management.

However, special training may be required for the dismantling of a non-active plant and the introduction of novel techniques for dealing with wastes. Basic requirements for a training program and for refresher training for decommissioning activities should be described in the decommissioning plan. Specialized expertise may be necessary in other areas such as dismantling and demolition; decontamination; robotics and remote handling; and fuel handling.

Determine Plan for Spent Fuel Storage and Disposal

The Government of Armenia will need to determine the plan for final disposal of SNF. The only technically feasible option is to ship the SNF out of the country, which is not currently possible due to political problems with neighboring countries. Within three years of plant shutdown, the plan for interim storage and disposal of spent fuel must be selected. This time frame is needed to allow time for procuring and installing additional dry storage if

needed as well as to finalize the decommissioning plan and other licensing submittals to ANRA.

Selection of Support Contractors

Planning an execution of ANPP decommissioning will require some level of support from contractors with expertise in nuclear plant decommissioning. This support is best obtained through competitive bid process where qualifications and price are considered. This process requires time for preparation of work scope and bid documents as well as proposal evaluation and contractor mobilization.

The practice on many US decommissioning projects has been to select different contractors for planning and for implementation. The bid documents for the planning support contractor(s) should be completed and sent to prospective bidders six years ahead of plant shutdown. This provides sufficient time for submission and review of proposals and contractor mobilization at the start of the five-year planning period prior to shutdown.

The schedule for selection of specialty contractors to support implementation activities will depend on the schedule of those activities but should be completed at least a year prior to plant shutdown.

Preparation of Decommissioning Work Packages

The major work during this planning period is preparation of detailed work packages including Decommissioning Plan Implementation Procedures (DPIPs). These procedures are the main drivers for the conduct of decommissioning activities. In order to be effective they should be clear, precise and easily understood. Each DPIP should be related to a specific action or task. Work package development also involves design activities for temporary structures or system modifications; detailed scheduling of work tasks and support requirements; procurement of special tools, parts, and materials; preparation of clearances and radiation permits, and establishing quality requirements and assurance measures.

Decommissioning work planning begins five years prior to shutdown to identify and plan all known work so that decommissioning can begin immediately upon shutdown. Work planning continues through out the decommissioning project as new work is identified.

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ANNEX A: DESCRIPTION OF DECOMMISSIONING SCENARIOS

A.1 DECON

For purposes of this analysis, the decommissioning activities for the DECON alternative are assumed to occur within the following four designated periods of time:

1. Planning and Preparation (5 years)
2. Defuel and Deactivate (3 year)
3. Spent Fuel Management (4 years),
4. Dismantlement (5 years)

The 5-year planning and preparation period will precede the final reactor shutdown of Unit 2. During this period plans and procedures will be developed that will be carried out during decommissioning. This planning includes finalization of the Decommissioning Plan, Health Physics Plan, ALARA program, and Waste Management Plan as well as development of licensing documents specified by ANRA. The major work during this planning period is preparation of detailed work packages including Decommissioning Plan Implementation Procedures (DPIPs). These procedures are the main drivers for the conduct of decommissioning activities. In order to be effective they should be clear, precise and easily understood. Each DPIP should be related to a specific action or task. Work package development also involves design activities for temporary structures or system modifications; detailed scheduling of work tasks and support requirements; procurement of special tools, parts, and materials; preparation of clearances and radiation permits, and establishing quality requirements and assurance measures.

Period 2 begins after the Unit 2 reactor has been shut down for the last time. Reactor support systems no longer needed and will then be shut down, deactivated, and put into a safe condition. In addition, the NUHOMS facility will be expanded to accommodate all spent fuel on-site.

Management of the spent fuel and spent fuel pools will occur during Period 3. Fuel from the last core must remain in the pools for a minimum of five years after final shutdown until it is sufficiently cool to permit transfer to the NUHOMS facility. Also during Period 3, the current low-level waste storage facility will be upgraded to accommodate current quantities of radioactive waste and the large quantities of D&D waste to be generated during the active decommissioning period. This new facility will be designed for permanent disposal of low- and intermediate-activity radioactive waste

Once the pool has been emptied, pool-related systems will be deactivated, and active decontamination and dismantlement will begin (Period 4). Large components will be removed from the reactor building and transported to upgraded new on-site burial facility. Only the reactor vessels will be cut into sections prior to transfer to the burial facility. The remaining large components (pressurizers, primary coolant pumps, steam generators, etc.) will be transported and buried intact. The smaller equipment (various pumps, valves, piping, heat exchangers, etc.) will be removed, cut up, packaged, and compacted as required before transfer to the burial facility.

Waste currently stored at the intermediate-activity waste facility (hereafter referred to as the Special Building) will be retrieved and treated as necessary and then stored at the existing on-site waste facility. The reactor internals and the components currently stored in the high-activity waste storage cells in the reactor building will be transferred to the NUHOMS facility.

Surfaces of structures will be decontaminated by washing and grinding, as appropriate, with the debris from these operations being transported to the burial facility. Once the structures are decontaminated, they will be demolished and buried in place. Buildings that were never contaminated will be left intact.

A.2 SAFESTOR/DECON 2

A SAFESTOR/DECON alternative may be adopted in which active D&D work is delayed for a nominal period of 50 years to allow enough time to accumulate the required decommissioning funds from various sources. The SAFESTOR/DECON alternative has five distinct periods:

1. Planning and Preparation (5 years)
2. Defuel and Deactivate (3 year)
3. Spent Fuel Management (4 years)
4. Safe Storage (50 years)
5. Dismantlement (3 years)

The first three SAFESTOR/DECON periods are identical to the corresponding periods in the DECON alternative. However, for SAFESTOR/DECON, a 50-year safe storage period is inserted between the spent fuel management period and the dismantlement period. At the beginning of the Safe Storage period the spent fuel pool will be drained and decontaminated. Once this is has been done, the staffing levels will be considerably reduced and the plant will enter a 27-year period of safe storage. During the last two years of this safe storage period the new low-level waste facility will be constructed.

The dismantlement period (Period 5) for SAFESTOR/DECON is the same as the dismantlement period for the DECON alternative. However, with the assumed decay of the high-active waste over the 50-year period, the reactor component waste stored in the high-activity waste storage cells can be transferred to the new low-level waste storage facility. The reactor internals can also be stored at this facility.

A.3 ENTOMB

For the ENTOMB scenario, it is assumed that the portion of the Reactor Building located below the operating floor (i.e., below the 10.5 - 11.8 meter level) can be converted into an entombment structure. This lower part of the Reactor Building consists of various rooms containing RCS components (steam generators, RCS pumps, piping, etc.). All systems in the Reactor Building will either be decontaminated for later demolition or else moved inside the entombment structure. All high-activity waste will be encapsulated in place. The waste stored in the Special Building and at the low-level waste storage facility will be retrieved, re-packaged and treated, as necessary, and then transported and encapsulated within the entombment structure.

The ENTOMB alternative has five periods:

1. Planning and Preparation (5 years)
2. Defuel and Deactivate (3 years)
3. Spent Fuel Management (4 years)
4. Preparation for Entombment (3 years)
5. Entombment (indefinite)

A description of the five periods follows.

Period 1: Planning and Preparation

This period is similar to the first period of the DECON scenario. However, because fewer pieces of specialized decommissioning equipment will have to be purchased for this alternative than for the previously discussed alternatives, these costs will be lower.

Period 2: Defuel and Deactivate

This period is the same as Period 2 of the DECON alternative.

Period 3: Spent Fuel Management

This period is similar to the period 3 of the DECON alternative, except that wastes will be retrieved from the low-level waste storage facility and placed in the reactor building.

Period 4: Preparation for Entombment

All low level waste will be stored within the entombment structure, rather than off-site or at the existing on-site storage facilities. For this reason it will be necessary to gain access to and/or enlarge the existing openings of some Reactor Building rooms so that the large quantities of waste may be transferred to these rooms. This will entail cutting passages through some walls and floors.

It is anticipated that the decontamination and removal of contaminated surfaces, process systems, and piping will also be carried out for the ENTOMB alternative, but the waste from these activities will be placed inside entombment volume and not stored at the existing storage facilities. In addition to this D&D waste, all waste stored at the Special Building and at the low-level waste storage facility will be moved into the entombment structure. Some of this waste may have to be repackaged and processed before it can be placed within the entombment volume. The Special Building and the low-level storage facility will then be decontaminated, with the secondary waste from this decontamination being stored within the entombment structure. The reactor components currently stored in the high-activity waste storage cells in the reactor building will be encapsulated with a 30-centimeter layer of concrete.

After all the spent fuel has been transferred to the NUHOMS site and all waste has been moved into the entombment volume, the sections of the operating floor that were removed earlier will be put back into place and all openings through the operating floor will be sealed by laying a 30-centimeter-thick slab of reinforced concrete over the operating floor. All penetrations through the containment barrier will be cut and the openings filled with concrete and capped with plates welded over the openings.

Period 5: Entombment

Since no decommissioning will be performed during this period, only a minimum number of personnel will be required at the site. A 24-hour security force of 6 persons will be maintained at the site. An inspector will enter the site grounds periodically to perform routine radiation surveys and examine the buildings and structures for deterioration.

A.4 SAFESTOR/ENTOMB 2

SAFESTOR/ENTOMB is a combination of the SAFESTOR/DECON alternative and the ENTOMB alternative. Thus, a period of entombment follows a safe storage period. There are six distinct time periods for this alternative.

1 Planning and Preparation (5 years)

2. Defuel and Deactivate (3 years)
3. Spent Fuel Management (4 years)
4. Safe Storage (50 years)
5. Preparation for Entomb (3 years)
6. Entombment (Indefinite)

A detailed description of the six periods follows.

Period 1: Planning and Preparation

This period is similar to the first period of the ENTOMB alternative.

Period 2: Defuel and Deactivate

This period is the same as for the SAFESTOR/DECON alternative. During Period 2, the current NUHOMS facility will be expanded to accommodate all spent nuclear fuel on the ANPP site.

Period 3: Spent Fuel Management

This period is similar to the period 3 of the DECON alternative, except that the components stored in the high-activity waste storage cells will not be moved to the NUHOMS facility but will be left in place. In addition, wastes will be retrieved from the low-level waste storage facility and placed in the reactor building. All fuel will be moved to the NUHOMS prior to the start of the Safe Storage period

Period 4: Safe Storage

The Safe Storage activities are the same as for the SAFESTOR/DECON alternative. In addition, the salt canisters stored in the Special Building will be put into high-integrity containers and then placed in the empty, drained spent fuel pools.

Period 5: Preparation for Entombment

The Special Building will be decontaminated and demolished during this period. The activities described in the corresponding sections of DECON alternative will also be carried out, with the waste from these activities being placed inside entombment volume. The sections of the operating floor that were removed earlier will be put back into place and all opening sealed with a 30-centimeter-thick slab of reinforced concrete. All penetrations through the containment barrier will be cut and the openings filled with concrete and capped with plates welded over the openings.

Period 6: Entombment

This period is identical to Period 5 of the ENTOMB alternative.

ANNEX B: SCHEDULE OF ANNUAL DECOMMISSIONING COSTS

This annex provides schedules for the annual costs for each of the decommissioning scenarios based on shutdown of the ANPP at the end of 2015. These schedules have been adapted from the schedules shown in Appendix C of the report by PNNL, *Preliminary Decommissioning Plan for the Armenian Nuclear Power Plant*, to reflect the later plant shutdown and the cost adjustments discussed in section 4 of this report.

Table B.1: Annual Decommissioning Costs for the DECON Scenario

Period	Year	Cost (Millions of Dollars)				
		D&D	Clean Demolition	Waste Management	Spent Fuel	Total Cost
Planning & Preparation	2011	4.3		0.4		4.7
Planning & Preparation	2012	4.3		0.4		4.7
Planning & Preparation	2013	4.3		0.4		4.7
Planning & Preparation	2014	4.3		0.2		4.5
Planning & Preparation	2015	4.3		0.2		4.5
Defuel & Deactivate	2016	11.1		0.2	1.8	13.1
Defuel & Deactivate	2017	11.1		0.2	6.3	17.6
Defuel & Deactivate	2018	11.1		0.2	10.5	21.8
Spent Fuel Management	2019	5.4		0.2	5.1	10.7
Spent Fuel Management	2020	5.4		1.5		6.9
Spent Fuel Management	2021	5.4		6.2		11.6
Spent Fuel Management	2022	5.4		6.2		11.6
Dismantlement	2023	15.0	5.0	6.2		26.2
Dismantlement	2024	15.0	5.0	3.0		23.0
Dismantlement	2025	15.0	5.0	5.6		25.6
Dismantlement	2026	15.0	5.0	3.7		23.7
Dismantlement	2027	15.0	5.0	2.8		22.8
Cap LL Waste Facility	2028			0.6		0.6
Cap LL Waste Facility	2029			0.6		0.6
Totals		151.25	25	38.8	23.7	238.75

Table B.2: Annual Decommissioning Costs for the SAFESTOR/DECON Scenario

		Cost (Millions of Dollars)				
Period	**Year**	**D&D**	**Clean Demolition**	**Waste Management**	**Spent Fuel**	**Total Cost**
Planning & Prep	2011	4.3		0.5		4.8
Planning & Prep	2012	4.3		0.5		4.8
Planning & Prep	2013	4.3		0.5		4.8
Planning & Prep	2014	4.3		0.3		4.6
Planning & Prep	2015	4.3		0.3		4.6
Defuel & Deactivate	2016	11.1		0.3	1.8	13.2
Defuel & Deactivate	2017	11.1		0.3	6.3	17.7
Defuel & Deactivate	2018	11.1		0.3	10.5	21.9
Spent Fuel Management	2019	5.4		2.8	5.1	13.3
Spent Fuel Management	2020	5.4		2.8		8.2
Spent Fuel Management	2021	5.4		2.8		8.2
Spent Fuel Management	2022	5.4		2.8		8.2
Safe Storage	2023	1.0		2.8		3.8
Safe Storage	2024	1.0		0.6		1.6
Safe Storage	2025	1.0		0.6		1.6
Safe Storage	2026	1.0				1.0
Safe Storage	2027	1.0				1.0
Safe Storage	2028	1.0				1.0
Safe Storage	2029	1.0				1.0
Safe Storage	2030	1.0				1.0
Safe Storage	2031	1.0				1.0
Safe Storage	2032	1.0				1.0
Safe Storage	2033	1.0				1.0
Safe Storage	2034	1.0				1.0
Safe Storage	2035	1.0				1.0
Safe Storage	2036	1.0				1.0
Safe Storage	2037	1.0				1.0
Safe Storage	2038	1.0				1.0
Safe Storage	2039	1.0				1.0
Safe Storage	2040	1.0				1.0
Safe Storage	2041	1.0				1.0
Safe Storage	2042	1.0				1.0
Safe Storage	2043	1.0				1.0
Safe Storage	2044	1.0				1.0
Safe Storage	2045	1.0				1.0
Safe Storage	2046	1.0				1.0
Safe Storage	2047	1.0				1.0
Safe Storage	2048	1.0				1.0
Safe Storage	2049	1.0				1.0
Safe Storage	2050	1.0				1.0

Period	Year	D&D	Clean Demolition	Waste Management	Spent Fuel	Total Cost
Safe Storage	2051	1.0				1.0
Safe Storage	2052	1.0				1.0
Safe Storage	2053	1.0				1.0
Safe Storage	2054	1.0				1.0
Safe Storage	2055	1.0				1.0
Safe Storage	2056	1.0				1.0
Safe Storage	2057	1.0				1.0
Safe Storage	2058	1.0				1.0
Safe Storage	2059	1.0				1.0
Safe Storage	2060	1.0				1.0
Safe Storage	2061	1.0				1.0
Safe Storage	2062	1.0				1.0
Safe Storage	2063	1.0				1.0
Safe Storage	2064	1.0				1.0
Safe Storage	2065	1.0				1.0
Safe Storage	2066	1.0				1.0
Safe Storage	2067	1.0				1.0
Safe Storage	2068	1.0				1.0
Safe Storage	2069	1.0				1.0
Safe Storage	2070	6.0				1.0
Safe Storage	2071	6.0		5.6		6.6
Safe Storage	2072	6.0		5.6		6.6
Dismantlement	2073	16.1	5.0	0.8		21.9
Dismantlement	2074	16.1	5.0	0.8		21.9
Dismantlement	2075	16.1	5.0	0.8		21.9
Dismantlement	2076	16.1	5.0	0.1		21.2
Dismantlement	2077	16.1	5.0	0.1		21.2
Cap Low Level Waste Fac.	2078			0.6		0.6
Cap Low Level Waste Fac.	2079			0.6		0.6
Total		223.75	25	33.2	23.7	305.65

Table B.3. Annual Decommissioning Costs for the Entomb Scenario

Period	Year	Cost (Millions of Dollars)				
		D&D	Clean Demolition	Waste Management	Spent Fuel	Total Cost
Planning & Prep	2011	4.0		0.1		4.1
Planning & Prep	2012	4.0		0.1		4.1
Planning & Prep	2013	4.0		0.1		4.1
Planning & Prep	2014	4.0		0.1		4.1
Planning & Prep	2015	4.0		0.1		4.1
Defuel & Deactivate	2016	11.0		0.1	1.8	12.9
Defuel & Deactivate	2017	11.0		0.1	6.3	17.4
Defuel & Deactivate	2018	11.0		0.1	10.5	21.6
Spent Fuel Management	2019	5.4		0.1	5.1	10.6
Spent Fuel Management	2020	5.4		0.1		5.5
Spent Fuel Management	2021	5.4		0.7		6.1
Spent Fuel Management	2022	5.4		0.8		6.2
Entombment Operations	2023	15.7	8.3	6.1		30.1
Entombment Operations	2024	15.7	8.3	6.2		30.2
Entombment Operations	2025	15.7	8.3	6.1		30.1
Entombment Period continues indefinitely	2026	9.2				9.2
Total		131.08	24.99	20.90	23.70	200.67

Table B.4: Annual Decommissioning Costs for the SAFSTOR/ENTOMB Scenario

Period	Year	Cost (Millions of Dollars)				
		D&D	Clean Demolition	Waste Management	Spent Fuel	Total Cost
Planning & Prep	2011	4.0		0.2		4.2
Planning & Prep	2012	4.0		0.2		4.2
Planning & Prep	2013	4.0		0.2		4.2
Planning & Prep	2014	4.0		0.2		4.2
Planning & Prep	2015	4.0		0.2		4.2
Defuel & Deactivate	2016	11.0		0.2	1.8	13.0
Defuel & Deactivate	2017	11.0		0.2	6.3	17.5
Defuel & Deactivate	2018	11.0		0.2	10.5	21.7
Spent Fuel Management	2019	5.4		0.6	5.1	11.1
Spent Fuel Management	2020	5.4		0.6		6.0
Spent Fuel Management	2021	5.4		0.6		6.0
Spent Fuel Management	2022	5.4		0.6		6.0
Safe Storage	2023	1.0		4.3		5.3
Safe Storage	2024	1.0		3.7		4.7
Safe Storage	2025	1.0		3.7		4.7
Safe Storage	2026	1.0				1.0
Safe Storage	2027	1.0				1.0
Safe Storage	2028	1.0				1.0
Safe Storage	2029	1.0				1.0
Safe Storage	2030	1.0				1.0
Safe Storage	2031	1.0				1.0
Safe Storage	2032	1.0				1.0
Safe Storage	2033	1.0				1.0
Safe Storage	2034	1.0				1.0
Safe Storage	2035	1.0				1.0
Safe Storage	2036	1.0				1.0
Safe Storage	2037	1.0				1.0
Safe Storage	2038	1.0				1.0
Safe Storage	2039	1.0				1.0
Safe Storage	2040	1.0				1.0
Safe Storage	2041	1.0				1.0
Safe Storage	2042	1.0				1.0
Safe Storage	2043	1.0				1.0
Safe Storage	2044	1.0				1.0
Safe Storage	2045	1.0				1.0

Period	Year	D&D	Clean Demolition	Waste Management	Spent Fuel	Total Cost
Safe Storage	2046	1.0				1.0
Safe Storage	2047	1.0				1.0
Safe Storage	2048	1.0				1.0
Safe Storage	2049	1.0				1.0
Safe Storage	2050	1.0				1.0
Safe Storage	2051	1.0				1.0
Safe Storage	2052	1.0				1.0
Safe Storage	2053	1.0				1.0
Safe Storage	2054	1.0				1.0
Safe Storage	2055	1.0				1.0
Safe Storage	2056	1.0				1.0
Safe Storage	2057	1.0				1.0
Safe Storage	2058	1.0				1.0
Safe Storage	2059	1.0				1.0
Safe Storage	2060	1.0				1.0
Safe Storage	2061	1.0				1.0
Safe Storage	2062	1.0				1.0
Safe Storage	2063	1.0				1.0
Safe Storage	2064	1.0				1.0
Safe Storage	2065	1.0				1.0
Safe Storage	2066	1.0				1.0
Safe Storage	2067	1.0				1.0
Safe Storage	2068	1.0				1.0
Safe Storage	2069	1.0				1.0
Safe Storage	2070	6.0				1.0
Safe Storage	2071	6.0				1.0
Safe Storage	2072	6.0				1.0
Entombment Operations	2073	17.7	8.3	1.5		27.5
Entombment Operations	2074	17.6	8.3	1.5		27.4
Entombment Operations	2075	17.6	8.3	1.5		27.4
Entombment Period continues indefinitely	2076	9.2				9.2
Total		203.83	25.00	20.16	23.70	272.69

2. APPENDIX A-2: ARMENIAN NPP CAPITAL IMPROVEMENT PROJECTS

The purpose of this paper is to explore some of the potential costs for safety, reliability and life extension projects at the ANPP to be considered in the Least Cost Generation Plan (LCGP).

SAFETY UPGRADES

The ANPP has defined a set of safety upgrade projects to be accomplished between 2005 and 2010 to address generic safety issues of the VVER 440/230 design reactor. These safety issues are described in IAEA-TECDOC-640, *Ranking Of Safety Issues For WWER-440 Model 230 Nuclear Power Plants*, 1992. The IAEA report ranks safety issues into four categories. Categories III and IV are issues of high safety concern, where immediate attention is required. Issues in Category II are also of safety concern, representing degradation of defense in depth, and action is required to resolve them. Issues in Category I reflect a departure from recognized international practices that should be addressed as part of actions to resolve higher priority issues.

The list of ANPP safety projects, as of November 2004 is shown in tables 1 through 3. The list includes 24 Category III, 19 Category II, and 5 Category I projects. For 18 of these projects, some or all of the costs of the project are expected to be provided by donor assistance from USDOE, TACIS, or DTI. In addition to the donor assistance shown in the table, USDOE has recently offered an additional $4 M for safety improvements in 2005-2006 time frame. However, for many of the projects, the donor assistance is limited to analytical or design work and does not include the cost of hardware or installation. For example, in 2005, DTI will be funding a project for developing an equipment qualification program but the cost for qualification testing and replacement of equipment, estimated to be as much as $5M, is not included in the DTI project scope. In other cases, the safety upgrade project involves analysis of the adequacy of existing plant systems. The results of the analysis may indicate the need for equipment modification or replacement that is not included in the scope of the upgrade project.

The costs to implement the identified ANPP safety upgrade projects were estimated by Scientech based on experience on similar projects in the US and cost data for similar projects at other VVER 440 plants reported in the literature. These estimated costs are shown in the right hand column of tables 1 through 3. The total cost for all projects that will not be supported by donor assistance is estimated to be between $22 and 94 million. If these safety upgrade projects are to be accomplished over the next five years (i.e., completed by the end of 2009) an average of $4.5 to 24.5 million per year in capital funds will be needed.

Operation beyond 2009 may require specific license approval by ANRA. The ANRA process and requirements for licensing are currently being developed. However, it can be anticipated that additional safety upgrades may be needed beyond 2009 to comply with license commitments.

PLANT LIFE EXTENSION

The VVER 440 design life is 30 years. With a startup date of 1980 and six years of shutdown from 1989 to 1995, the ANPP unit 2 will reach the end of design life by 2016. However,

ANPP staff is discussing the feasibility of extending the life of the ANPP by 20 years to 2035. Life extension projects are being pursued at similar design plants at Novovoronezh and Kola NPPs in Russia.

Plant life extension requires a systematic and comprehensive assessment of age related degradation mechanisms for all systems, structures, and components at the NPP. In the US, where these assessments are now fairly routine and are supported by a large industry database, the average cost of a license renewal application is about $10-12 M. The assessment often identifies many components that must be repaired or replaced to ensure safe operations in the years of extended life. Examples of high cost replacements are steam generators, pressurizer, reactor vessel head, and plant cabling. For VVER 440 type reactors, experiences at other plants indicate that annealing of the reactor vessel to reduce radiation damage to the steel may be required. The total cost of these life extension upgrades can not be determined with any certainty, but will probably be between $100 and $300 M. Most of this resource would need to be spent in the time frame of 2013-2018 for a life extension beyond 2016.

RELIABILITY AND EFFICIENCY PROJECTS

In addition to nuclear safety upgrade projects, ANPP will require other capital projects to ensure reliability, thermal efficiency, and personnel safety. For example, plant management has indicated that renovation of the main condenser would improve plant efficiency and electrical output significantly at a cost of $1.5 million. Based on the age of the plant, it can be expected that other high cost projects such as feed water heater replacement, turbine controls upgrade, or plant instrument modernization will be needed over the next several years to ensure reliable performance of the plant. Other capital projects are needed to manage radioactive waste that is accumulating at the plant and for spent fuel storage for operation beyond 2009. The cost of these non-safety capital projects has not been estimated.

RECOMMENDATIONS

The capital cost requirements for continuing operation of ANPP, including improvements to address IAEA safety issues, should be determined through detailed review of the plant's project plans and schedule. Non-safety upgrade projects needed to maintain reliability, efficiency, and personnel safety should be identified, scheduled and estimated. This information could be developed in cooperation with ANPP management in the context of developing a long-range capital spending plan for the plant.

For the LCGP analysis, a cost of $ 24 M per year for safety improvements during 2006 through 2010 should be used in a screening analysis. If the LCGP analysis is to consider ANPP operation beyond 2016, an additional allowance of $50M per year during the period 2013-2018 for life extension projects should be included. If the LCGP screening analyses indicate that the optimum LCGP solution is sensitive to these screening values, a more detailed cost estimation study with support of ANPP staff would need to be performed.

Table A-2.1: Category III Safety Upgrade Projects

No.	Specification	Objective of activity	Implementation date	Notes	Cost Estimate
1.	Development and implementation of activity on continuous improvement of reactor protection logic and channeling separation and independency, as far as possible	Requirement of OPB-88	2005		Scope unknown. $0.1-1M
2.	Completion of Leak-Before-Break concept applicability analysis at ANPP and equipment of ANPP with diagnostic systems based on the results of analysis.	Compensation of design deficiency of primary circuit pipeline rupture leak	2004	TACIS program	The TACIS project may cover analysis. Implementation cost may include leak detection system and pipe snubbers. $0-2.5M
3.	Development of Unit 2 Probabilistic Safety Analysis level 1	ANRA requirements	2004	Partially funded by TACIS program and Government of Great Britain	No hardware. DOE is funding experts to review and guide PSA. Approximately 4-6 man yr labor for plant staff
4.	Implementation of Seismic Reevaluation Program for ANPP Unit 2	Improvement of seismic safety	According to schedule agreed with ANRA		Analysis work done by Armenian experts and plant staff. Results may result in piping or support modifications. $0-1M
5.	Development of Safety Analysis Report (SAR) for ANPP Unit 2	Safety assessment	According to schedule agreed with ANRA	The activity is partially funded by US DOE	No hardware. Approximately 12-18 man yr labor for plant staff. Review of Safety Analysis by ANRA may result in additional commitments for safety upgrades.
6.	Implementation of accident localization system with installation of jet condenser	Improvement of safety functions efficiency: “Retention of radioactive materials within limits”, “Provision of confinement integrity”.	2006	Partial funding by TACIS program	A pressure suppression device (jet vortex condenser discharging through a water pool. TACIS project includes analysis to justify system and establish design input. Design, fabrication, installation $3-18M
7.	Implementation of post-accident hydrogen monitoring and installation of hydrogen recombiner system	Implementation of TECDOC-640 recommendations Problem-system 2.	2006		Procure and install recombiners and controls. $0.75-2M

8.	Implementation of activity set to include primary pipeline ND-100mm rupture in design-basis accidents scope - Improvement of DG velocity and voltage control units - Reconstruction of the automatic load sequencer circuit - Assessment of environment for safety systems in boron unit and other rooms where temperature conditions can change sharply affected by new design-basis accidents.	ANRA requirements Implementation of IAEA Mission recommendations Issue – TECDOC-640 Ventilation/cooling capability	2005 2005 2004	US DOE Program	DG load controller funded by DOE. Assessment of environmental conditions may result in additional equipment modifications. $0-1M
9.	Completion of reconstruction of I category auxiliaries uninterruptible power supply system	Replacement of obsolete reversible motor generators – 1,2	2004	Partial funding of US DOE	Batteries, inverters, chargers. $1-2M
10.	Reconstruction of sprinkler system	Separation of current system into two independent and equivalent channels	2004		$0.5-1M for piping, supports, controls
11.	Primary pressure control system reconstruction	Provision of primary pressure automatic control	2005	TACIS program	
12.	Installation of check valves on SG feed-line in close proximity to SGs	Elimination of SG dump in case of feed-line break	2005		Procure and install check valves, additional pipe supports. $4-6M
13.	Modernization of electrical equipment of reactor control and protection system with replacement of Automatic Power Controller and Automatic Monitoring of Neutron Flux (intermediate and power range)	The system is obsolete and worn-out	2008		Scope unknown. $0.5-2.5m
14.	Modernization of source range “INEY” AMNF (Automatic Monitoring of Neutron Flux) system	Provision of neutron flux monitoring in transients	2005	TACIS program	Scope unknown. $0.5-2.5m
15.	Provision of sufficient air filtration for Unit 2 control room and protection of control room from missiles	Maintaining of normal working conditions at control room	2005		Scope unknown. $0.5-2.5m
16.	Development and implementation of “Feed and Bleed” procedure	Mitigation of beyond the design accidents	2004		Procedure work. Pressurizer safety valves have already been replaced.

17.	Development of full-scale simulator	Provision of effective training	2006		Simulator building, control panels, computer, simulation programs $6-10 M.
18.	Installation of automatic continuous boron concentration monitoring device	Requirement of OPB	2005		$0.25-0.5M
19.	Protection of SG compartment sumps against clogging	Reduction of probability for safety system pump suction clogging	2006		Design, fabrication, and installation of sump screens $1-6M
20.	Installation of reactor vessel head venting and water level control system	Elimination of core uncovering probability	2005	TACIS program	Design, procurement, installation of valves, vent piping, instrumentation. $1-4M
21.	Development of safety important I&C equipment qualification program in compliance with current standards on equipment qualification	Implementation of IAEA Mission recommendations Issue-TECDOC-640 I&C and electric equipment qualification	2006		Project to identify equipment funded by DTI. Equipment qualification testing and procurement of replacements $0.5-5M
22.	Modification of POISK-2M manipulator to enable the application of ABIT method to reactor vessel external surface	Implementation of IAEA Mission recommendations Isse-TECDOC-640 Embrittlement. Validation of correctness	2004		Scope unknown. $0.1-1M
23.	Determination of reactor vessel internal cladding and external surface mechanical properties with ABIT method within Additional Technical Specification to tender documentation on reactor vessel	Implementation of IAEA Mission recommendations Isse-TECDOC-640 Embrittlement. Validation of correctness	Outage-2004		Scope unknown. Probably requires foreign laboratory services $0.1-1M
24.	Implementation of comparative improved calculation of the ANPP reactor vessel fatigue strength and calculation of brittle fracture resistance according Russian and Western methodologies	Implementation of IAEA Mission recommendations Isse-TECDOC-640 Embrittlement. Validation of correctness	2005		Scope unknown. Probably requires foreign laboratory services $0.1-1M

Table A-2.2: Category II Safety Upgrade Projects

No.	Specification	Objective of activity	Implementation date	Notes	Cost Estimate
1.	Implementation of pressurizer POSRV control with COP system (cold overpressure protection system) signals	Provision of valve automatic control	2005	Supplied under TACIS program	$0.2-1M
2.	Replacement of auxiliaries PT30 cabinet input circuit-breakers with high reliability circuit-breakers	Provision of protection selectivity	2005	US DOE program	$0.2-1M
3.	Replacement of information computing system IVM-500	Provision of information completeness and truth in compliance with design functions	2004	US DOE program	$3-6M
4.	New software package “Cascade” purchase and implementation in fuel cladding test	Implementation of TECDOC-640 recommendations problem-core 2	2005		Software purchase $0.1-.2
5.	Purchase of a new spectrometry set for application in fuel cladding test	Implementation of TECDOC-640 recommendations problem-core 3	2008		$0.1-.2
6.	SG level automatic control system modernization	Upgrading of level maintaining reliability in SG	2005	TACIS program	Replace control loop modules $.6-1.2M
7.	Implementation of activities ensuring unit transfer to safe state after seismic event	Provision of residual heat removal	2005		Scope unknown. Assume service water piping replacement $1-3M
8.	Improvement of fuel storage pool water purification system	Provision of purified water quality	2010		$0.5-2M
9.	Improvement of plant radiation monitoring system	Provision of compliance with advanced Technical Documentation	2005	TACIS program	$0.5-2M
10.	Improvement of in-core monitoring system	Measurement of neutron flux in core and identification of fission-heat	2006		$2-6M
11.	Construction of emergency control panel	Specifications of Technical Documentation	2006		$.2-.8M
12.	Replacement of 6kV oil breakers of II category auxiliaries uninterruptible power supply system with 6kV non-oil breakers	Non-propagation of potential ignitions in in-house switchgear	2004	TACIS program	$.3-.9M

13.	Development of Quality Assurance Program of Unit operation	New Technical Documentation requirements	2004	The activity is partially funded by Government of Great Britain	
14.	Analysis of consequences of high energy piping ruptures close to SS and SRS	Analysis of reliable operation of SS and SRS	2008		May need new pipe, restraints, shields $0-1M
15.	Identification of necessary I&C for post-accident monitoring and prevision of the implementation	Implementation of IAEA Mission recommendations Issue – TECDOC-640 Emergency control I&C	2006		$0.1-3M
16.	Application of eddy-current method for test of reactor vessel surface within Main Technical Specification to tender documentation on reactor vessel test	Implementation of IAEA Mission recommendations Issue – TECDOC-640 Vessel in-service test. Corrosion monitoring	2004		Test equipment and modification to thermal insulation $0.1-.5M
17.	Development of guideline on emergency procedures Development of emergency procedures	Implementation of IAEA Mission recommendations Issue – TECDOC-640 Analysis of severe accidents	2005 2007		$0.1-.25M
18.	Development of guidelines on beyond the design basis accident management	Implementation of IAEA Mission recommendations Issue – TECDOC-640 Analysis of severe accidents	2005		$0.1-.25M
19.	Purchase and mastering the use of up-to-date portable and stationary instrumentation and units.	Improvement of safety and reliability	2004÷2010		$0.1-.5M

Table A-2.3: Category I Safety Upgrade Projects

No.	Specification	Objective of activity	Implementation date	Notes	Cost Estimate
1.	Reconstruction of feed water distribution headers inside the 2 SG-4, 5	Provision of maintainability of worn-out header elements	2005		$0.5-2.5M
2.	Installation of primary and secondary automatic water chemistry control system	Provision of continuous chemical control	2005	TACIS program	$0.1-0.5M
3.	Revision and reapproval of correcting activities taking into account the issue of new technical standard documentation and work experience from 1995 to 2003	Implementation of joint Decision N2 of RA Ministry of Energy and ANRA of October 12, 1995	2004		Scope unknown
4.	Development and approval of ANPP Unit 2 decommissioning program	Technical Documentation requirements	2010		$6-10M
5.	Improvement of physical security system	Requirement of IAEA documents INRCIRC/225/Rev 4. Physical security of nuclear materials and nuclear facilities	2005	US DOE Program $2-5M	$2-5M

3. APPENDIX A-3: NEW NUCLEAR GENERATION OPTIONS

EXECUTIVE SUMMARY

The primary objective of this study is to examine the technical characteristics, capital, and life cycle costs of nuclear plant alternatives for expanding the electrical generation capacity in Armenia by the year 2015. The results of this survey provide input for the analysis and the development of a Least Cost Generation Plan (LCGP) for electric power sector of Armenia. The study also discusses some of the institutional and project schedule related issues to be considered in the decision to build a new nuclear plant in Armenia.

The past several years have seen a significant increase in the level of interest and activity related to nuclear power plants around the world. Some of the reasons for this renewed enthusiasm for nuclear power are:

- The entry into force of the Kyoto Protocol, requiring reduction in carbon dioxide and other fossil fuel emissions,
- The continued improvement in safety performance and reduction in operating costs of the existing nuclear plants,
- Rising prices and occasional shortages of fossil fuels,
- The need for additional generation in rapidly growing economies, and
- Advanced reactor designs, offering improved safety and performance are under licensing review.

About 30 power reactors are currently being constructed in 11 countries, and an equal number are in the procurement or planning stage to be completed by 2015. In addition to major building programs in India, Korea, China, Japan, and Russia, several smaller countries, such as Finland, Romania, and Bulgaria are constructing new nuclear plants. Planned nuclear plants include evolutionary and advanced designs with enhanced safety features, higher capacity, improved efficiency, and reduced construction time.

Because Armenia has experience in operation of nuclear plants, there are several factors, such as an experienced nuclear workforce and an effective Nuclear Regulatory Authority, which would favor a nuclear power plant for generation expansion or replacement in Armenia. However, there are a number of institutional issues that should be addressed in the decision to select a nuclear plant for replacement of the existing ANPP generation. Because most of the nuclear plant designs currently available have considerably more generating capacity than is needed for the Armenia system, a nuclear project will also require significant investment in transmission capacity for electricity export. For many nuclear plant designs, key pieces of equipment are too large and heavy to be transported over currently available transportation routes. A nuclear project involving Western suppliers and financing would most likely require Armenia to establish higher levels of liability protection. The current nuclear trained work force is aging and substantial training programs will be needed to augment the workforce for the new plant.

The suitability of the nuclear plant site under modern criteria must be evaluated through a formal process that includes early public involvement in site selection. A related issue is the need to perform an environmental impact assessment to qualify for financing guarantees or low interest loans from Western financial organizations. Also, a substantial increase in ANRA staff will be needed for licensing new unit(s).

Nuclear plant designs that are currently available to be completed by 2015 include the CANDU 6 and ACR-1000 from Canada, the AP1000 and ESBWR from the US, the EPR form France and Germany, and the VVER1000 from Russia. Of these, the CANDU 6 is the only design that is currently operating, although two models of VVER 1000 are under construction. All of the designs have, or will soon have, design certification by their national nuclear regulatory authority. The ACR -1000, AP1000, ESBWR, and EPR have a number of features to enhance safety, improve thermal efficiency, and reduce construction cost and schedule.

The CANDU 6 has some particularly attractive features for the situation in Armenia including:

- Online refueling to eliminate refueling outages,
- Smaller components that are more easily transported into the country,
- Use of natural uranium widens the source of fuel supply,
- Flexibility and reliability of a two unit plant that can meet the domestic demand with one unit

The principal drawback of the CANDU 6 and ACR – 1000 design is the need for a year long shutdown to replace reactor tubes after 30 years of operation.

The estimated capital and life cycle costs and construction schedules for five of the nuclear plant designs currently available for Armenia were developed based on information provided by the vendors and published in the literature. The ESBWR was not included in the cost estimates because cost and schedule data are not publicly available. The cost data were used in a least cost planning model to determine production costs of a new nuclear power plant in comparison to other forms of generation. The results show a relatively small variance in the production costs for the different types of reactor plants. This small variance is within the uncertainty of the publicly available cost data. Nuclear plant production costs are much more sensitive to differences in the cost of capital to finance plant construction than they are to minor differences in the construction and operating cost.

The ACR-1000, AP1000, and EPR are designed with a number of features to improve constructability, and construction schedules of 48 months from contract award to fuel load are achievable. However, there are many other activities in a nuclear plant project that must be performed before or after the actual construction period. Activities such as site selection, environmental assessment, preparation of bid specifications, evaluation of tenders, licensing, and startup testing must be considered in establishing a project schedule. A schedule of nine years from project initiation until commercial operation would be a feasible but challenging schedule for a new nuclear plant project in Armenia.

ACRONYMS AND ABBREVIATIONS USED IN THE REPORT

ABWR –Advanced Boiling Water Reactor 220 – 600 MW

ACR – Advanced CANDU Reactor

AECL - Atomic Energy of Canada Limited

ANPP - Armenian Nuclear Power Plant

ANRA - Armenian Nuclear Regulatory Authority

AP – Advanced Passive

APR - Advanced Pressurized Reactors

ASN - French Nuclear Safety Authority

CANDU - CANada Deuterium Uranium.

DOE - Department of Energy

EPR – European Pressurized Reactor

EPRI – Electric Power Research Institute

EIA - Environmental Impact Assessment

ESBWR – Economic Simplified Boiling Water Reactor

FBR - Fast breeder reactor

FOAKE-First-of-a-Kind-Engineering

IAEA – International Atomic Energy Agency

KNSP - Korean Standard Nuclear Plant

NEA - Nuclear Energy Agency

NRC – (US) Nuclear Regulatory Commission

MoE - Ministry of Energy,

MW – Megawatts electric

OECD - Organization for Economic Co-Operation and Development

PHWR – Pressurized Heavy Water Reactor

PWR - Pressurized Water Reactor

SEU - slightly enriched uranium

US – United States

VVER – Water cooled Water moderated Energy Reactor

1. INTRODUCTION

The purpose of this study is to examine the technical characteristics, capital, and life cycle costs of nuclear plant alternatives for expanding the electrical generation capacity in Armenia when the existing Armenian nuclear power plant (ANPP) is retired. The study also discusses some of the institutional issues to be considered in the decision to build a new nuclear plant in Armenia.

ANPP unit 2 provides a substantial portion of the electrical energy supply in Armenia. As part of the planning for new electrical generation supplies for Armenia between now and the time when ANPP is retired, nuclear generation technologies were surveyed to identify those that would be technically and economically feasible for Armenia. The results of this survey provide input to least cost planning analysis of the electric power sector of Armenia. This report presents the results of the survey of nuclear generation options.

Based on 30-year design life of reactor vessel, ANPP unit 2 could continue to operate through 2015. While there have been several proposals to shutdown unit 2 earlier because of concerns with the safety of the VVER-440/230 reactor design, there has also been consideration of extending the life of the ANPP beyond 2015. Because the retirement date for ANPP has not yet been determined, the year 2015 was selected as the time frame for start of operation of any new nuclear generation plant.

2. INTERNATIONAL NUCLEAR PROJECTS

The past several years have seen a significant increase in interest and activity related to nuclear power plants around the world. Some of the reasons for this renewed enthusiasm for nuclear power are:

- The entry into force of the Kyoto Protocol, requiring reduction in carbon dioxide and other fossil fuel emissions,
- The continued improvement in safety performance and reduction in operating costs of the existing nuclear plants,
- Rising prices and occasional shortages of fossil fuels,
- The need for additional generation in rapidly growing economies, and
- Advanced reactor designs, offering improved safety and performance are under licensing review.

The International Atomic Energy Agency (IAEA) has significantly increased its projection of world nuclear generating capacity [(1)]. It now anticipates at least 60 new plants in the next 15 years. About 30 power reactors are currently being constructed in 11 countries, notably China, the Republic of Korea, Japan, India, and Russia. Construction is well-advanced on many of them. Plants currently being constructed generally represent mature designs with demonstrated safety, cost, and operating performance, such as the Advanced Boiling Water Reactor (ABWR), the Pressurized Heavy Water Reactor (PHWR), and the Russian design Pressurized Water Reactor (VVER). Planned nuclear plants include evolutionary and advanced designs with enhanced safety features, higher capacity, improved efficiency, and reduced construction time. These plants include the European Pressurized Reactor (EPR), the Advanced CANDU Reactor (ACR), an evolutionary design VVER 1000, the Korean Advanced Pressurized Reactors (APR), and the US designed AP1000 and Economic Simplified Boiling Water Reactor (ESBWR).

This section presents examples of nuclear plant construction projects currently in progress or planned for completion within the next ten years in selected countries around the world.

Finland

In late 2004, Finland's electric generating company TVO began construction of a single unit, 1600 MW capacity EPR plant at Olkiluoto, the site of two of the countries four existing reactors. The Olkiluoto 3 plant is scheduled for startup in 2009.

Romania

In Romania, the construction of the second CANDU 6 unit at Cernavoda is in progress with startup scheduled for 2006. The two unit Cernavoda plant will have a generating capacity of 1347 MW.

Bulgaria

The Bulgarian government has decided to proceed with plans to construct a new, two unit nuclear power plant at the Belene site[(2)]. Belene was started as a four unit VVER 1000 plant in 1986, but work was abandoned in 1990 due to lack of funds. Bulgaria is considering proposals from several vendors for two pressurized water reactors of 1,000 megawatts each. The first of the two reactors is expected to be operational by 2011 and the second by 2013.

Russia

In Russia, there are four reactor units under construction and due for completion by 2010. Three of these are VVER 1000 model 320, a pressurized water reactor with a net generating capacity of 950 MW. The fourth unit is an 800 MW fast breeder reactor, the BN-800. Five other reactors are planned to replace some existing plants, and 19 reactors are planned to add new capacity by 2020 [(1)].

South Korea

In South Korea, eight nuclear units are under construction or on order and planned for completion by 2015. Four of these are of the 950 MW Korean Standard Nuclear Plant (KNSP) design, which is based on the Combustion Engineering System 80 reactor plant. The second set of units planned are four Advanced Pressurized Reactors (APR) of 1400 MW. These APR-1400 designs have evolved from the US System 80+ which has US NRC design certification, and have been known as the Korean Next-Generation Reactor [(1)].

Japan

Japan has two nuclear units under construction for startup by 2009. Eight additional nuclear units are planned for startup by 2015. Most of these are the ABWR with generating capacities of 1375 to 1385 MW [(1)].

China

In China six nuclear units, including two CANDU 6 PHWRs, have been placed in operation during the past three years. Currently, two VVER 1000 model V-428 nuclear plants (known as AES-91 nuclear plant) each with 950 MW capacity are being constructed at Tianwan for startup in 2005 and 2006 [(1)]. The AES-91 differs from earlier VVER 1000 designs in that it uses a Digital controls system designed by Siemens. China is currently soliciting bids for four new nuclear units with contracts to be awarded in 2005 for completion by 2011. Candidates are the AP 1000, the EPR of 1600 MW, and the VVER 1000 model V-392 (also known as the AES-92 nuclear plant)[(3)]. Eight additional nuclear units are planned for startup by 2015.

India

India has nine reactors under construction that are expected to be completed by 2010. These include two VVER 1000 model V-392 (AES-92) units being constructed at Koodankulam. Additionally, there are six PHWRs of Indian design and a 470 MW prototype fast breeder reactor (FBR). Between 2010 and 2020, construction of four 220 MW PHWRs, ten 700 MW PHWRs, three 500 MW FBRs, and up to six 1000 MW VVERs is projected [(1)].

United States

Several utilities in the US are active in preparing Early Site Permit and Construction/Operation License applications for submission to the NRC. These applications reference several reactor technologies that have completed or will complete NRC design certification, including the AP1000, ABWR, and EPR. Applications for at least three new nuclear units are being prepared with NRC approval expected by 2009. When the applications are approved by NRC, the utility will have authorization to construct and operate the referenced nuclear plant design at the designated site without further regulatory action.

3. ISSUES RELATED TO NEW NUCLEAR GENERATION IN ARMENIA

Since Republic of Armenia has experience in operation of nuclear plants, it is logical to evaluate new nuclear generation expansion options for the study time horizon of 2015. Several factors would indicate that a nuclear power plant could be a feasible candidate for generation expansion or replacement in Armenia. The ANPP was restarted in 1995 and has been successfully operated since that time. Armenia has a current workforce experienced in operating a nuclear power plant. The Armenian Nuclear Regulatory Authority has a trained, experienced staff and has demonstrated the ability to establish and enforce regulations.

However, there are a number of institutional issues that should be addressed in the decision to select a nuclear plant for replacement of the existing ANPP generation. These issues are discussed in the following sections.

Grid Capacity

Based on domestic load growth forecasts, a nuclear plant with capacity of more than 750 MW would not be efficiently operated in the Armenian system. The reliability of the system would be severely challenged if one generator were to carry more than half of the system load. If Armenia was to select a 750 MW nuclear unit, during the off peak period the system load may be below the maximum capacity of this one unit. Because nuclear plants are designed to operate as base load, a nuclear plant with more than 750 MW capacity would not be efficiently operated in the Armenian system. There is only one nuclear plant design of less than 750 MW that is currently available for export to Armenia (the CANDU 6).

However, it is also reasonable to plan for expansion of Armenia's electrical generation capacity to export power to other countries in the region. There are currently grid connections and agreements to exchange power with Iran and Georgia. Transmission connections to Turkey and Azerbaijan exist and could be activated if agreements were reached. However, transmission of large amounts of power to neighboring countries will require substantial improvements to the transmission lines in Armenia as well as in the other countries. Construction of large nuclear plant for electricity export may also require significant investment in transmission capacity.

Energy Independence

An important attribute of the nuclear generation expansion option in Armenia is that it would reduce the country's vulnerability to short-term interruptions in imported fossil fuel supplies. Advanced nuclear reactors only need to be refueled once in 18 to 24 months. If a supply of fresh fuel is maintained at the plant, a nuclear plant could provide a substantial portion of the country's electric energy needs for up to four years without importing fuel.

However, it should be recognized that the nuclear expansion option would make Armenia highly dependent on a single source of nuclear fuel. Nuclear fuel designs are unique for each reactor design. It is technically possible to get an alternative fuel vendor to manufacture nuclear fuel for a particular design. However, it would be very expensive to establish a fuel fabrication capability for a single customer and would require several years to qualify the safety of the alternative fuel through analyses and testing. The ability to establish a long term relationship for nuclear fuel from a source that is not susceptible to political or business interruption is a critical factor in achieving the energy independence offered by a replacement nuclear plant.

High Level Radioactive Waste

Plans for a new nuclear plant in Armenia would have to include provisions for long term storage high level radioactive waste including spent nuclear fuel. US regulations currently prohibit receiving spent fuel from other countries and the planned repository at Yucca Mountain is yet to be approved. Canada is still developing plans for long term disposal in Whitteshell. Britain, France, and Russia have accepted spent fuel from other countries for reprocessing, but all three require that the products and wastes from reprocessing be returned to the customer. Although Russia is considering changes in the law mandating this approach, Russian fuel reprocessing facility at Mayak is currently shut down.

In recent years, there has been increased attention to the possibility of international storage or disposal sites for spent fuel. These would be sites that would accept spent fuel from multiple countries, either in their region or around the world. This focus on international repositories has been driven by a number of factors including the increasingly urgent need for additional spent fuel storage capacity around the world. However, there are currently no specific plans and it cannot be estimated when such a facility would become available. Without a disposal option, spent fuel from a new nuclear plant in Armenia would be kept in interim storage for an indefinite period.

Nuclear Liability

The lack of adequate third-party liability protection has impeded implementation of technical improvements to Soviet-designed reactors in some countries. Western contractors and suppliers fear they would be held liable in the event of an accident. This issue may also affect the willingness of western equipment suppliers, construction contractors, or financial institutions to participate in a new nuclear plant project in Armenia.

Armenia has signed the IAEA Vienna Convention on Civil Liability for Nuclear Damage of 1963. The convention is based on the following main principles:

- Liability is channeled exclusively to the operators of the nuclear installations;
- Liability of the operator is absolute, i.e. the operator is held liable except for "acts of armed conflict, hostilities, civil war or insurrection";
- Liability of the operator is limited in amount. Under the Vienna Convention the upper ceiling is not fixed; but it may be limited by legislation in each State.
- The operator must maintain insurance or other financial security for an amount corresponding to its liability or the limit set by the Installation State. Beyond this level the Installation State can provide public funds but can also have recourse to the operator;
- Jurisdiction over actions lies exclusively with the courts of the Contracting Party in whose territory the nuclear incident occurred;
- Non-discrimination of victims on the grounds of nationality, domicile or residence.

Following the Chernobyl accident in 1986, the IAEA initiated work to improve the basic convention and established a more comprehensive liability regime[(5)]. In 1997, a Protocol to Amend the Vienna Convention was adopted by delegates from over 80 states. The amended IAEA Vienna Convention sets the possible limit of the operator's liability at not less than about $ 400 million. The Protocol also broadens the definition of nuclear damage (now also addressing the concept of environmental damage and preventive measures), extends the geographical scope of the Convention, and extends the period during which claims may be brought for loss of life and personal injury. However, Armenia has not

signed the 1997 Protocol to Amend the Vienna Convention, in part because the liability limits are considered to be too high[(6)].

Currently, the Government of Armenia would be liable for damages from a nuclear accident. Neither the joint stock company nor the government carries insurance for nuclear accident liability. With an annual national budget of about $500 million, the Government of Armenia may not be viewed as having sufficient resources to cover potential liability in the event of an accident.

A new nuclear project involving Western suppliers and financing would most likely require Armenia to sign the 1997 Protocol to Amend the Vienna Convention and to obtain liability insurance to the limits of the protocol.

Nuclear Regulatory Authority

Government control of nuclear safety in Armenia is implemented by the Armenian Nuclear Regulatory Agency (ANRA), which is vested with the authority to implement licensing activity targeted at design of nuclear installations, site selection, construction, commissioning and decommissioning. Funding of the ANRA is provided exclusively from the RoA State Budget. ANRA receives technical assistance from international organizations' assistance programs.

ANRA has a staff of 16 including one resident inspector at ANPP, and in addition to ANPP, the staff is responsible for oversight of radioactive sources. The ANRA is also supported by the experts of the Scientific-Research Center for Nuclear and Radiation Safety. ANRA is funded by the Armenia government with some support from other countries. Regulations for licensing a new NPP are contained in regulations currently under development. The licensing process involves sight selection, construction permit, design permit, operating license, and decommissioning plan, all of which must be approved by parliament. Sight selection would include public hearings.

Assuming the new nuclear plant design has been certified by the nuclear regulator in its country of origin, a comprehensive regulatory review of the submittals for the various phases of the licensing process for a new nuclear plant would require 60-80 person years of work. This level of effort would overwhelm the existing ANRA staff and supporting organization. The Government of Armenia will have to provide substantially more personnel (16-20 people) and training resources to ANRA for a period of several years to ensure the licensing approval of a new plant is accomplished in a reasonable time frame.

Work Force

Armenia has a workforce experienced in operation of a nuclear power plant. However, a significant portion of the current ANPP workforce is approaching retirement age and will not be available for the new plant. Substantial training of engineers, operators, technicians and managers will be needed during the plant construction period to provide a qualified workforce for operation of a new nuclear plant. Training programs will also be needed to establish a skilled labor pool for plant construction.

Transportation

Much of the equipment and building materials needed to build a new nuclear plant are too large and heavy to be transported over the existing railroad, bridges, and tunnels of the "northern route" through Georgia. The only useable rail transportation route is the railroad through Azerbaijan. Construction of the nuclear plant will require major upgrades to the

transportation routes through Georgia or restoration of other rail access to Armenia will be required.

Location

The current ANNP site was designed for two additional nuclear units. However, the suitability of this location under modern sighting criteria must be evaluated. Because the site is in a relatively high seismic zone, seismic design criteria for safety related structures and equipment would be higher than normal, adding to the plant's capital cost. The supply of water to the site is limited and bringing additional water flow to the site to supply normal and emergency cooling may divert water from other users. Also, the proximity of the site to air traffic routes may have a significant impact on the risk of an accident. Furthermore, the current and projected population and local transportation resources may present a challenge to assuring evacuation of the emergency planning zones for the new plant. These and other sight characteristics must be thoroughly evaluated in assessing the suitability of the current ANNP site for a new plant. Experience indicates that early public involvement in site selection and evaluation process is essential.

Financing

Financing for international nuclear plant projects often involves special loans or loan guarantees from the government of the nuclear plant vendor. These financing mechanisms significantly lower the financing costs for the project. For example, the Export-Import Bank of the US (Ex-Im Bank) has provided preliminary commitment to Westinghouse for a combination of guaranteed and/or direct loans of up to almost $5 billion for the bid to construct four nuclear power plants at two sites in China [(7)]. Similarly, Export Development Canada (EDC) has provided financing support for the CANDU 6 units recently constructed at Qinshan, China and for the AECL bid for the China projects. Russia has provided about one half of the financing for the Koodankulam project in India.

In addition to evaluating the customer's ability to pay, export financing organizations such as Ex-Im Bank and EDC have guidelines for reviewing the technical, social, and environmental aspects of projects considered to be potentially hazardous, such as nuclear plants [(8)]. The guidelines address issues such as the legal and regulatory framework of the host country, the plans for plant construction and operation, and environmental impact assessment (EIA) of the project. In order to be eligible for financing support, the host country must demonstrate that international standards for nuclear and environmental safety will be maintained through out the project.

Preparing the EIA and application for financial support is a lengthy process and may require development of regulations or policies to meet the guidelines of the export financing organizations. This process must be started as early as possible to assure the availability of low rate financing.

4. NUCLEAR PLANT DESIGNS

If the project were started within the next several years, there are several nuclear plant designs that could be constructed in time to replace the generation of the ANPP in the time frame of 2015 to 2020. This section describes the technical characteristics of several of the nuclear plant designs that would be available in this time frame.

CANDU 6

The CANDU 6 is designed by Atomic Energy of Canada Limited (AECL). CANDU stands for "CANada Deuterium Uranium". CANDU is a Pressurized Heavy Water Reactor (PHWR) that uses heavy water (deuterium oxide) for moderator and coolant, and natural uranium for fuel.

The CANDU 6 is the current generation plant with a net generation capacity of 674 MW. CANDU 6 units are typically built in sets of two to provide a plant with generating capacity of 1348 MW. Ten CANDU 6 reactors are currently in operation in Canada, Korea, Argentina, China, and Romania [(9)]. An additional unit is under construction in Romania. The CANDU 6 design has been licensed by the Canadian regulatory authority as well as the regulators in the other countries where they are operating.

The CANDU plants have a number of unique features that are would be beneficial in the situation of Armenia:

- Use of natural uranium widens the source of supply and makes fuel fabrication easier. There is no need for uranium enrichment facility.
- A two unit plant provides more flexibility and reliability for a small grid such as in Armenia. If one unit goes offline, the other unit could supply most of the domestic energy demand.
- CANDU design uses pressure tubes rather than a large pressure vessel to hold the fuel, which allows on power refueling, resulting in potentially higher capacity factors. The top performing CANDU 6 units have achieved capacity factors in excess of 96 percent.
- The use of a pressure tube reactor eliminates the need for a large reactor vessel, which will be difficult to transport into Armenia.

There are two primary disadvantages to the CANDU 6 design. Because the plant uses pressurized heavy water for a moderator, there is potential for leaks from heavy water systems. Makeup supplies of heavy water must be obtained periodically or manufactured by special equipment onsite. The other disadvantage is the need to replace the pressure tubes of the reactor after about 30 years of operation. Complete replacement of all pressure tubes requires a one year outage about half way through the 60 year life of the reactor. This would not be such a serious problem for a two unit plant, where the schedules for the retubing outage could be adjusted to ensure one unit was available.

Recent CANDU construction projects have met challenging schedule targets [(9)]. Wolsong Units 2, 3 and 4 are CANDU 6 units in Korea, which were completed in 1997, 1998 and 1999 respectively—all on time and on budget. The Wolsong Unit 3 project took a total of 69 months, from the contract effective date to commercial operation. This included a 46-month construction period from the time of the issuing of the construction permit to fuel loading.

ACR-1000

The Advanced CANDU Reactor (ACR) is an evolution of the CANDU 6 design [10]. The ACR is a pressurized water reactor that uses slightly enriched uranium (SEU) fuel, light water coolant, and smaller amounts of cool, low pressure heavy water as a moderator.

The ACR was initially designed for generating capacity of 700 MW (ACR-700) and intended to be installed in a two unit plant, similar to the CANDU 6. Subsequently, AECL has revised the design to produce 1125 MW (ACR 1000) to be more competitive with other nuclear plant designs. A safety certification of the ACR-1000 design by Canadian Nuclear Safety Commissions is currently underway, and certification by USNRC is planned by 2012. The ACR 1000 is being proposed by AECL for the four unit project in China. Two or more ACR 1000 units are expected to be operating in Canada by 2015.

The ACR design retains CANDU strengths such as on-power fueling and no heavy reactor vessel. However, the evolutionary design of the ACR provides increases in plant efficiency as well as reduction in construction and operating cost as compared to the CANDU 6 [11]. The use of SEU fuel, while more expensive, provides a reduced core size and improved safety margins. Using light water as coolant eliminates some systems and greatly reduces the need for make up heavy water. The plant design also incorporates passive safety systems that provide better safety assurance while reducing construction and maintenance costs. The turbine cycle has been improved significantly to provide better thermal efficiency.

A major area of improvement in the ACR design is in the area of construction optimization. The ACR design emphasizes layout for streamlined construction through a highly modularized design. By preparing the complete reactor building design in the form of drop-in modules, the total project schedule—including engineering, procurement, construction and commissioning—can be substantially reduced. This allows a critical path schedule, for a replication unit, of 48 months with a construction duration of less than 36 months.

Like the CANDU 6, the ACR plant will require a one year outage for replacement of reactor tubes after about 30 years of operation. In the case of Armenia, where there may not be alternative generation available, a year long outage of a single nuclear unit could present a problem.

AP1000

The AP1000 is a PWR with a 1,117 MW generating capacity. It is essentially a higher power version of Westinghouse's 600-megawatt design, the AP600, which the NRC certified in 1999 [12]. The Westinghouse AP1000 standard plant design received NRC design certification in 2004. The AP1000 design certification document is widely regarded as the most comprehensive safety case prepared for a nuclear design.

AP is sometimes taken to mean "Advanced Passive". The principal advantage of the AP 1000 as compared to older PWR designs is safety. The safety margins of the AP 1000 are considerably higher and the likelihood of failure is much lower because the plant relies on naturally occurring phenomena such as gravity, natural circulation and condensation, guaranteeing a safe shutdown of the plant even in the highly unlikely event of an accident.

The additional benefit of passive design is that passive safety systems are significantly simpler than the traditional PWR safety systems. They do not require the large network of safety support systems needed in typical nuclear plants, such as AC power, HVAC (heating, ventilation & air conditioning), cooling water systems and seismic buildings to house these components. Simplification of plant systems, combined with increased plant operating margins, reduces the actions required by the operator. The AP1000 has 50 percent fewer valves, 83 percent less piping, 87 percent less control cable, 35 percent

fewer pumps and 50 percent less seismic building volume than a similarly sized conventional plant [13]. These reductions in equipment and bulk quantities lead to major savings in plant costs and construction schedules.

The plant is designed to be constructed modularly, which will greatly improve construction quality while reducing construction time to about 36 months from the time concrete is first poured until the time that fuel is loaded into the core. This shortened construction period greatly reduces the amount of time investment capital that will be tied up before the plant is operational. Westinghouse projects a 60 month total schedule with 36 months from first concrete to fuel load [13].

At this time, no AP1000 plants are scheduled for construction. However, the design is being proposed by Westinghouse for the four unit project in China. The AP1000 is included as a reference plant in all of the Construction/Operating License applications being prepared by US utilities.

European Pressurized Reactor

Areva has developed a large (1600 and up to 1750 MW) European Pressurized Water reactor (EPR), which was confirmed in mid 1995 as the new standard design for France. The French Nuclear Safety Authority (ASN) has issued design approval for Areva's 1600 MW EPR, equivalent to US design certification. US design certification is planned to begin in 2007.

The first EPR unit is under construction at Olkiluoto in Finland. The second unit is planned for Flamanville in France. The EPR design has been proposed for four new units in China. At least one US Utility, Constellation Energy has included the EPR as a reference plant for their Construction/Operation License application.

The EPR is derived from the French N4 and German Konvoi types and is expected to provide power about 10% cheaper than the N4.[14] It will operate flexibly to follow loads, have high fuel burn-up and the highest thermal efficiency of any light water reactor, at 36%. Availability is expected to be 92% over a 60-year service life, obtained through two year refueling cycles, ten day refueling outages, and in-operation maintenance on quadruple redundant safety systems.

VVER 1000

The Russian Joint Stock Company, ATOMSTROYEXPORT, is offering a new generation of VVER 1000 power units. These designs have been developed to meet current IAEA safety requirements [15]. The VVER 1000 model V-428 is known as AES-91 nuclear plant and has 950 MW net generating capacity. The AES-91 differs from earlier VVER 1000 designs in that it uses a digital controls system designed by Siemens. Two of these plants are being constructed in China and the design was bid for the Finland Olkiluoto project.

The latest version of VVER-1000, the V-392, is also known as AES-92 nuclear power plant. The AES-92 has 950 MW generating capacity. In addition to digital controls, the AES-92 has a number of active safety systems similar to those found on a traditional Western PWR. The AES-92 is designed for an 18 month refueling cycle. Two AES-92 units are being constructed in India and two units are planned for construction as Novovoronezh 6 and 7 in Russia. It is expected that ATOMSTROYEXPORT offer the AES-92 design in its bid for the four unit project in China.

Advanced Boiling Water Reactor

General Electric Company's (GE) 1300 MW Advanced Boiling Water Reactor (ABWR) nuclear plant was developed in cooperation with the Tokyo Electric Power Company and GE's partners Hitachi and Toshiba. Two ABWR units are in the fourth cycle of successful operation in Japan and two more are under construction in Taiwan [(16)]. The ABWR received USNRC standard design certification in May 1997. Additionally, an early sight permit application based on the ABWR design has been submitted to the USNRC by a group led by Entergy. The ABWR has also received licensing approval in Japan and Taiwan. The ABWR is currently being reviewed by the European Utility Organization against European regulatory requirements.

If an ABWR were to be built in the U.S., GE estimates, using an extensive database of costs and quantities based upon the Taiwan project, that the overnight construction cost would today be $1400/kW. There is a potential for further cost reductions that would reduce the plant cost to $1200/kW.

The ABWR's operating cycle is 18 months with capability up to 24 months. The refueling outages duration is 43 days. These outage lengths assume that there is only normal maintenance work and no major turbine generator work. ABWRs have a number of design features that reduce the number and duration of forced outages, major maintenance outages and plant derates. Two major contributors to the improved availability factor of 87% are advanced materials and better designed recirculating systems.

The ABWRs in Japan were constructed in only 51 months, as measured from the first concrete construction activity to commercial operation.

GE is replacing the ABWR design with an Economic Simplified Boiling Water Reactor (ESBWR) design which has higher capacity and passive safety features [(17)]. The ESBWR has been submitted to NRC for design approval, which is expected by the end of 2006. The 1,500 MW ESBWR design features design simplicity and passive safety features. Like the AP1000, ESBWR depends on fewer "active" mechanical systems, with associated pumps and valves, and instead relies on more reliable "passive" systems that utilize natural forces, including natural circulation and gravity.

The ESBWR is being referenced in one of the Construction/Operating License applications being prepared by US utilities. GE estimates that if all goes as planned with the review process, formal construction of an ESBWR in the US could begin in 2010, with commercial operation to begin as early as 2014 [(17)]. However, currently no ESBWR cost estimates are publicly available.

5. SUMMARY OF COST DATA

The estimated capital and life cycle cost data for five nuclear plant designs currently available for Armenia are summarized in table 1. Cost data for ABWR were not surveyed because the design will not be offered for much longer and cost data for ESBWR are not yet publicly available.

Table 1: Summary of New Nuclear Plant Cost Data

	AP-1000 (USA)	**2 x CANDU 6 (Canada)**	**ACR 1000 (Canada)**	**VVER 1000 AES-92 (Russia)**	**EPR (France/ Germany)**
Nuclear Plant Type	PWR	PHWR	PWR	PWR	PWR
Net Capacity (MW)	1117	1347	1,125	950	1600
Net efficiency %	33.0%	32.6%	34.7%	30.8%	36.0%
Net Heat Rate (@ 100% (Btu/kWh)	10,340	10,452	9,830	11,078	9,478
Construction (years) Ground break to Operation	6	7	5	6	5
Construction Pattern (%/yr)	10/20/20/20/20/20	8/21/27.1/19.6/12/7.2/5.1	8/22/29/21/20	1/9/17/17/33/23	10/22/28/20/20
Overnight Capital Cost (2005$/kW)	1,376	1,475	1,475	1,500	1,864
Overnight Capital Cost Incl. 12% IDC ($2005/kW)	2,076	2,498	2,038	2,034	2,592
Decommissioning Cost (million $2005)	231	298	233	214	447
O&M Cost: ($/kW/yr)	65	70.7	69.9	63.3	71
Fuel Cost ($/MMBtu)				0.4327	0.513
- Fuel purchase	0.44500	0.16434	0.36620		
- Spent fuel disposal	0.11	0.108	0.1058		
Life of Unit, yrs	60	60	60	50	60
Availability Factor	0.93	0.918	0.94	0.84	0.91

The cost figures presented in the table are based on public information, information provided from vendors, and expert judgments. Fuel costs and other variable operating and maintenance (O&M) costs are derived from net output, that is, net capacity multiplied by the capacity factor at which the plants are assumed to operate.

Overnight construction costs provided by most of the references for the ACR 1000 and AP 1000 and VVER 1000 were for a two-unit plant. Except for the CANDU 6, the cost figures presented in the table represent a single unit plant. If two reactors are built at the same site at the same time, experience suggests that both units can be built for 7 to 12 percent less than if they were built separately[18]. The cost reduction is due to ability to schedule work crews and construction equipment more expeditiously, with less downtime, as well

as economies in procurement and related support costs. For this reason, the reference cost per kW estimates were escalated 10 percent for the single unit plant.

For the CANDU 6, cost estimates and construction schedules are based on information provided by the vendor [19] [20] and published studies[21]. For the ACR-1000, cost estimates were developed by scaling the information on the ACR-700 [19][20][21][22]. For the AP1000, cost estimates and construction schedules are based on information in published papers and reports [13] [18] [22] [23]. EPR cost estimates and construction schedules are also based on information in published papers and reports [14] [22] .

Capital cost estimates for VVER 1000 were based on reported total cost budgets for projects in China and India[24][25]. Operating and fuel costs and construction schedules are based on information provided by the Czech Republic in a survey performed by the Organization for Economic Co-Operation and Development (OECD) [22].

The escalation of fuel prices is a judgment based on current fuel market conditions and trends. Uranium fuel prices fell throughout most of the 1990s, largely due to the sale of secondary supplies released at the end of the Cold War. However, the availability of these supplies has declined substantially and uranium cost has doubled over the past two years. In the next 20 years, prices will continue to rise as secondary supplies are depleted and commercial inventories drop[18]. The long lead time between uranium discovery and production, typically 10 to 15 years, means that producers must be assured that prices will remain high enough to support investment in exploration before new uranium sources become available. Demand for conversion and enrichment services is also expected to rise as secondary supplies of enriched uranium are depleted.

The cost data were used in the least cost planning model to determine production costs of a new nuclear power plant for generation. The results show a relative small variance in the production costs for the different types of reactor plants. This small variance is within the uncertainty of the publicly available cost data. Nuclear plant production costs are much more sensitive to differences in the cost of capital to finance plant construction than they are to minor differences in the construction and operating cost.

6. CONSTRUCTION SCHEDULE

The schedule for construction of a nuclear plant is determined by a number of factors. The ACR-1000, AP1000, and EPR are designed with a number of features to improve constructability, and construction schedules of 48 months from contract award to fuel load are achievable.

There are a number of other activities in a nuclear plant project that must be considered in establishing a schedule. The licensing requirements for a new plant in Armenia have not been established and would probably require a year or more to put in place after the decision is made to proceed. Because of the technical complexity of the plant and the legal complexities of the financing, preparation of bid specifications and tender documents, preparation of proposals, bid evaluation, and contract negotiations can take two to three years. Once the reactor design has been selected, engineering design of the balance of plant and support facilities will require approximately 12 months. Depending on the Armenian licensing requirements, a site permit based on a comprehensive environmental assessment may be required before construction can begin. Preparing this assessment can often be performed in parallel with procurement and design but review and approval by the regulator may extend beyond these activities. In addition to construction of the reactor plant, the project may involve substantial site infrastructure such as cooling towers, transportation facilities, or a training center that can extend the total construction period. Following initial critical stage, there is a period of start up testing that may take eight months or more.

The hypothetical nine-year schedule for construction of a new nuclear plant in Armenia is shown below.

Activity	Duration in Months	Completion time in Months after Decision to proceed with Nuclear Plant
1. Obtain financing commitments	36	36
2. Establish regulatory framework	12	24
3. Site selection and assessment	24	24
4. Prepare Specifications	12	30
5. Conduct tender	18	48
6. Engineering design	12	60
7. Plant construction	40	100
6. Plant Startup	8	108

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APPENDIX B:

Renewable Energy Technologies and Resources

Armenian Power Sector 2006 Least Cost Generation Plan

EXECUTIVE SUMMARY

Although Armenia has extensive renewable resources, renewable energy generation is not considered to be available on demand and can not be relied on for base-load power generation. An exception is biomass resources which can be used to produce gas and store it for on demand use. However, availability of micro and small gas turbines, spare parts, and skilled labor appear to be a hurdle for the use of this technology. Bio-gasification is currently being practiced in Armenia for production of gas for heating applications.

Solar technology is also applied in Armenia primarily for heating applications. These projects have been initiated and funded by international donor organizations. However, most of these projects are currently in disrepair due to lack of their economic viability and lack of funds for spare parts and repairs.

Integration of wind and hydro power generation may improve the availability of these two renewable resources combined, but additional studies are needed to confirm technical and economic viability of this approach.

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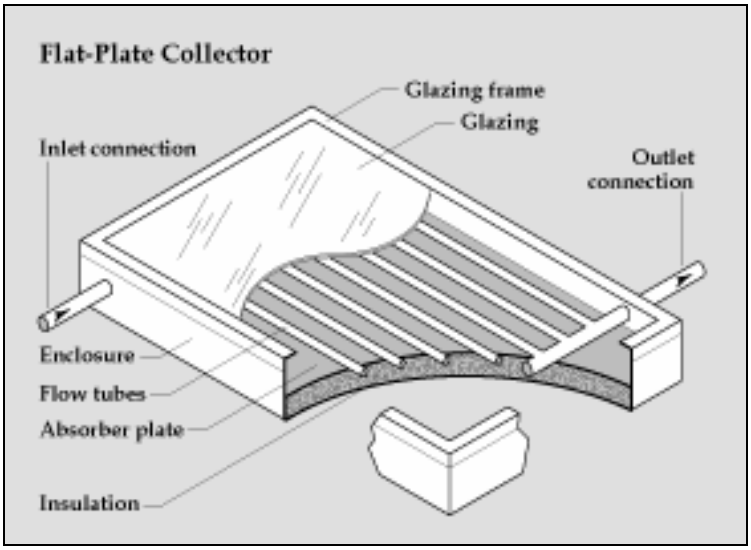
1. SOLAR WATER HEATERS

The sun's energy has been used to heat water for domestic and commercial uses for decades. Use of solar heated water systems is mandated by law in some countries, notably Israel. Equipment required for solar heat water system can be manufactured locally in many countries including Armenia. Solar water heaters, subsidized by foreign governments, have been installed and used in Armenia; however, they are not economically viable today.

The most commonly used solar water heating systems have five major components: a solar collector, a storage tank, a circulation system to move a fluid from the collector to the storage tank and back, a conventional heating system as a backup, and a control system to regulate the operation of the system. Of these components, the most important is the solar collector. To reduce costs, some systems use a modified conventional water heater as both a storage tank and a backup system. The most common type of solar collector is the flat-plate collector (Figure B.1) which is a large, flat box with a glass cover and dark-colored metal plates inside that absorbs and transfer solar energy to a fluid.

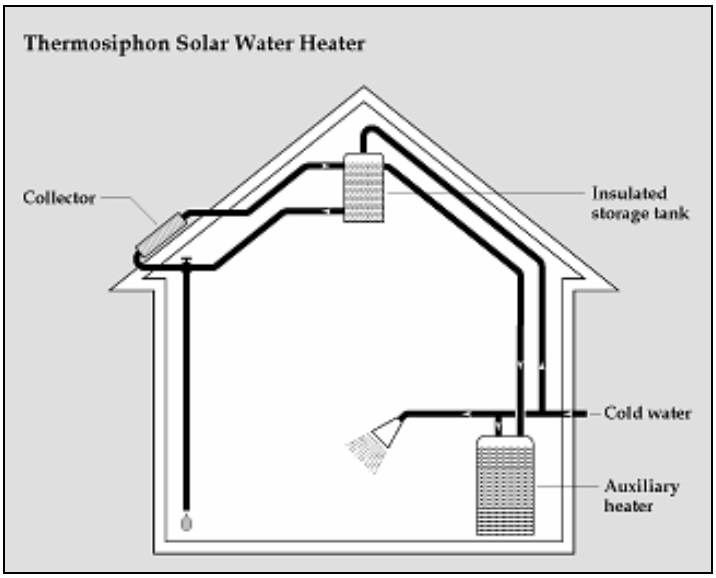
Figure B.1 Flat-Plate Collector[1]



There are two types of solar water heaters, passive and active, depending on how the fluid is moved between the collectors and the storage tank. Passive systems use natural convection to move water through the circulation system between a storage tank that is placed higher than the solar collector, allowing convective processes to produce a natural flow in the system as the warmer fluid flows upward from the solar collector and the cooler fluid from the storage tank flows downward. Passive systems are reliable and easy to maintain because they have no pumps. However, these systems are not best suited for cold climates where hard freezes occur often. In addition, the storage tank requires significant structural support since it has to be placed higher than the solar collector. A passive system is depicted in Figure B.2.

[1] DOE Office of Energy Efficiency and Renewable Energy, http://www.eere.energy.gov/solar/sh_basics.html

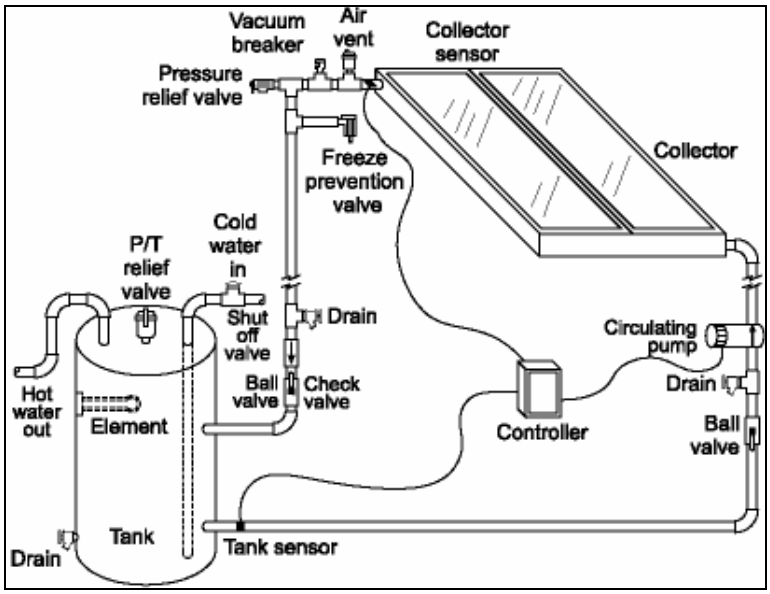
Figure B.2 Passive System[2]



An active system uses electric pumps and valves to move fluid through the circulation system. These systems can be used in cold climates where hard freezing occurs.

Active systems can be either direct or indirect systems. In a direct system, the water is heated directly in the solar collector and is circulated through the storage tank as needed. Direct systems are usually used in milder climates where freezing is not a concern or areas where the water is not hard or acidic. Figure B.3 shows an active, direct system.

Figure B.3 Active, Direct System[3]



In an indirect system, a heat transfer fluid, such as glycol or diluted antifreeze, is passed through the solar collector before transferring its energy to the water in the storage tank through a heat exchanger. Figure B.4 shows an active, indirect system using a flat-plate

[2] http://www.eere.energy.gov/consumerinfo/heatcool/hc_water_type.html
[3] http://www.fsec.ucf.edu/Pubs/EnergyNotes/En-9.htm

collector and diluted antifreeze as the heating fluid. A second type of indirect system, known as a drainback system use water as the heat transfer fluid, but has sensors that drains the fluid into a special reservoir when the temperature drops into the freezing range. The advantage of this system is that it does not involve any potentially toxic fluids like antifreeze. Figure B.5 is an example of a drainback system.

Figure B.4 Active, Indirect Water Heater System[4]

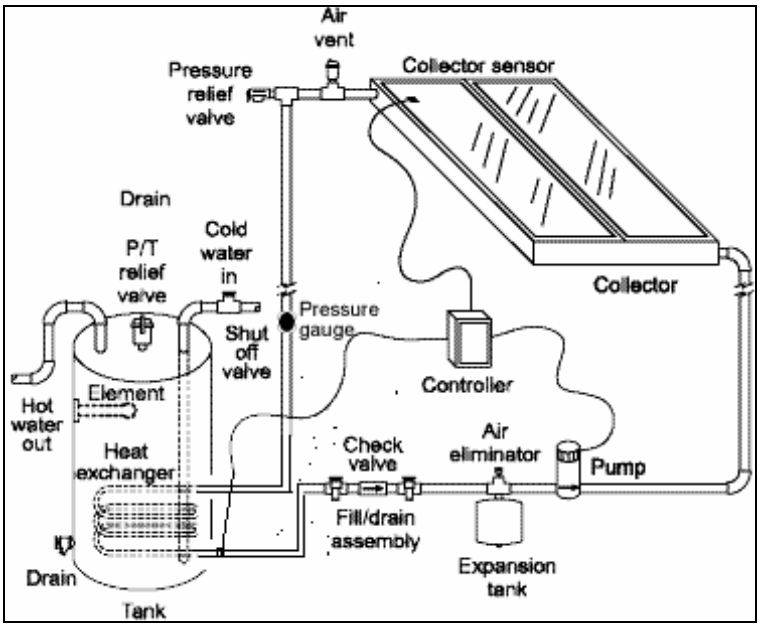
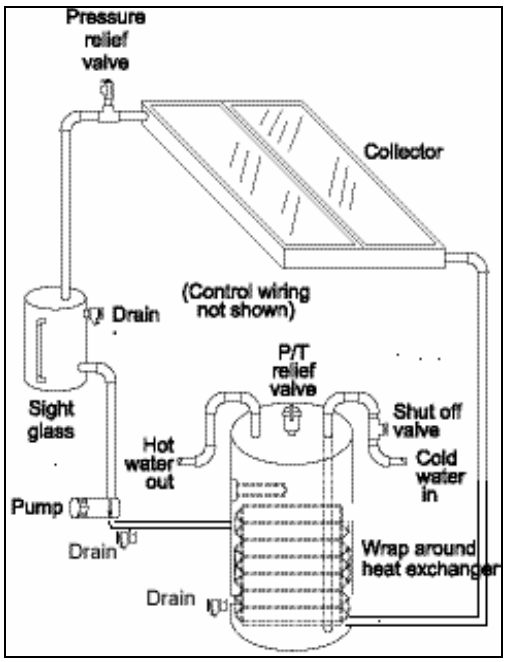


Figure B.5 Active, Indirect Water Heater System with Drainback[5]



[4] http://www.fsec.ucf.edu/Pubs/EnergyNotes/En-9.htm
[5] http://www.fsec.ucf.edu/Pubs/EnergyNotes/En-9.htm

2. ANAEROBIC DIGESTER FOR BIOGAS PRODUCTION

The conversion of manure to biogas as a source of energy for water and space heating and as a replacement for electrical heaters in livestock operations is gaining some interest and attention in Armenia. The conversion of organic waste (manure) into methane gas and fertilizer using anaerobic digester technology is already used extensively in Europe and the United States to generate heat and electricity, primarily due to stringent environmental regulations. Anaerobic conversion of biomass to biogas has been extensively studied in Armenia since the early 1960s. Recently, several pilot scale demonstration projects have been built and operated with support from USAID and other donors. Today, at least one commercial project for converting manure, from 75 to 100 head of dairy cows, to biogas is under construction in Armenia. A large poultry farm is also seeking financing for the construction of an anaerobic digester facility for converting chicken waste, including the waste from a chicken slaughter house, to produce biogas. At this chicken farm, the biogas produced at a pilot scale facility is currently being used for space heating and hot water production. As in most other countries, the Armenian farming community's interest in this technology appears to be driven more by its environmental attribute rather than the economic benefits of energy production. Figure B-6 shows a chicken waste collection and processing site in Armenia. The odor, insects, and discharge of untreated wastewater from the settling ponds are typical problems associated with chicken waste or other animal waste disposal.

Figure B.6 Chicken Waste Collection and Processing

Replacing electrical water and space heaters with biogas heaters can reduce the electrical consumption of some farms in Armenia by up to 50%. However, the total potential for power generation using anaerobic digestion processes in conjunction with heat engines or micro turbines is estimated to be about 15 MW in Armenia.

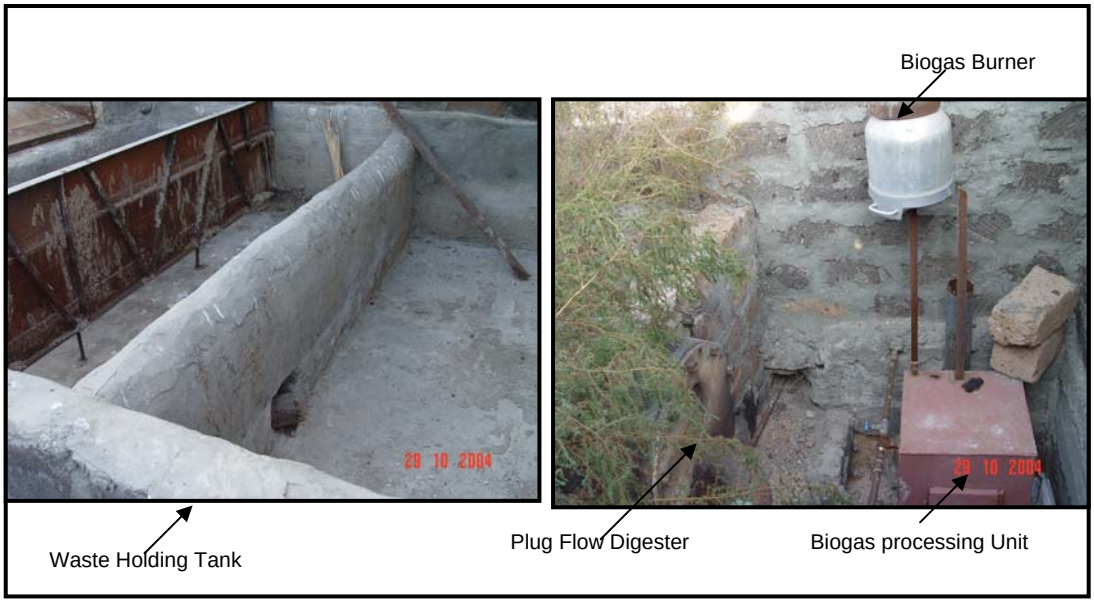
The digester technology is proven and many of the operational difficulties encountered earlier are resolved by automating digester operation. In an anaerobic digestion process, the bacteria residing in the digester converts waste matter and water, in the absence of air, to methane, carbon dioxide, nutrient-rich water (liquid fertilizer) and nitrogen-rich compost (solid fertilizer). The bacteria needed in a digester include fermenting bacteria, acid-forming bacteria and methane-producing bacteria; and all three exist naturally in manure. The amount of methane produced depends greatly on the type and operating conditions of the digester which in turn is dictated by the amount of waste, waste collection method, waste age, and the local climate.

There are basically three types of anaerobic digesters. The simplest is the covered lagoon type. In this type of system, the existing waste collection lagoon is enclosed with a plastic cover to allow the anaerobic bacteria to dominate the lagoon's ecosystem and to produce biogas and organic residue. The biogas is then collected through pipes from the lagoon's surface. Covered lagoons are not very efficient because they operate in the lower temperature end of the digester operating range. The biogas produced in covered lagoons is about 50% methane and 50% carbon dioxide.

The second type of anaerobic digester is called a plug or batch flow digester. It consists of a long in-ground horizontal, water-tight tank. The tank is tilted slightly to allow the material to move from the tank's input end to the output end. Waste is directed to the input end of the tank, the digestion process occurs in the tank, and the residue is removed from the lower end of the tank. The biogas is removed from the tank freeboard (space above the liquid in the tank) and contains about 60% methane and 40% carbon dioxide. Figure B.7 pictures a batch flow digester pilot plant that was operated earlier at Agro Service Farm, outside Yerevan, Armenia.

Batch flow digesters operate at the higher temperature range than covered lagoon type digesters and are more efficient.

Figure B.7 Plug Flow Digester Pilot Plant at Agro Service Farm



The third type of digester is the continuous mix digester. It consists of an above ground tank that is partially filled with a mixture of water and manure (normally about 95% water and 5% solids) and is equipped with a mixing or recycling mechanism. The digester is fed from a feed tank and its temperature is controlled to maintain a mesophilic (30 to 35°C) or

thermophilic (50 to 55°C) range. Thermophilic digesters are more efficient in producing biogas but also require more heat to maintain the higher tank temperature. Continuous flow systems are more efficient than plug flow digesters.

Two mespohilic digester pilot plants are shown on Figures B.8 and B.9, one processing chicken waste and the other cow manure. A commercial plant that is under construction for converting waste from 75 to 100 head of dairy cows to biogas is shown on Figure B.10.

The plant at Black Ox Farm, like most modern plants in the U.S. and Western Europe, relies on an automated process monitoring and control system to maintain the desired operating conditions in the digester tank for maximizing biogas production. Automation has helped to resolve many of the operational difficulties faced by U.S. and Western European farmers in the early 1970s. Most U.S. and European farmers, operating digesters, also utilize gas engines or micro turbines to generate heat and electricity. The current practice in Armenia, however, appears to focus on utilizing biogas for heat generation only. This is primarily due to a lack of experience with small gas engines and micro- turbines, availability of micro- turbines and gas engines, including spare parts and related repair and maintenance services, in Armenia.

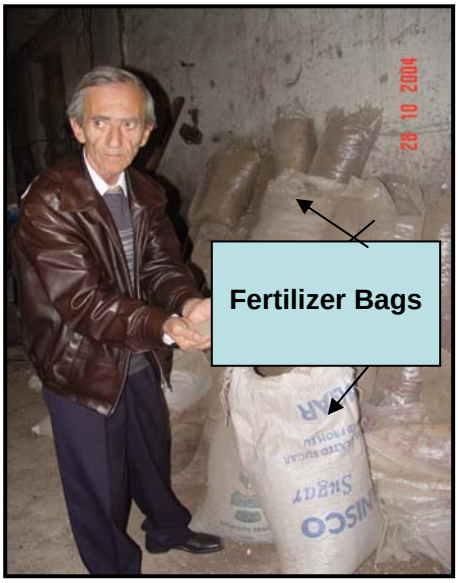
As in Armenia, most commercial units in the U.S. and Europe, utilize one digester tank. However, some U.S. researchers and developers have proposed projects using more than one digester tank in order to increase methane gas yields. In a multi-tank system, bacterial activities for fermentation, acid formation, or methane generation is enhanced by maintaining different operating conditions at each tank.

In the short term, production of biogas from manure may lead to the replacement of some electrical heaters with gas or hot water heaters in some Armenian farms. In the long term, it may be used to meet the electrical as well as heat demand of some of the Armenia's farms. However, it is not projected to have a significant impact on the total demand for electricity over the next 20 years and should not be considered as a DSM technology or tool, particularly without other tools that discourage electricity use at peak times.

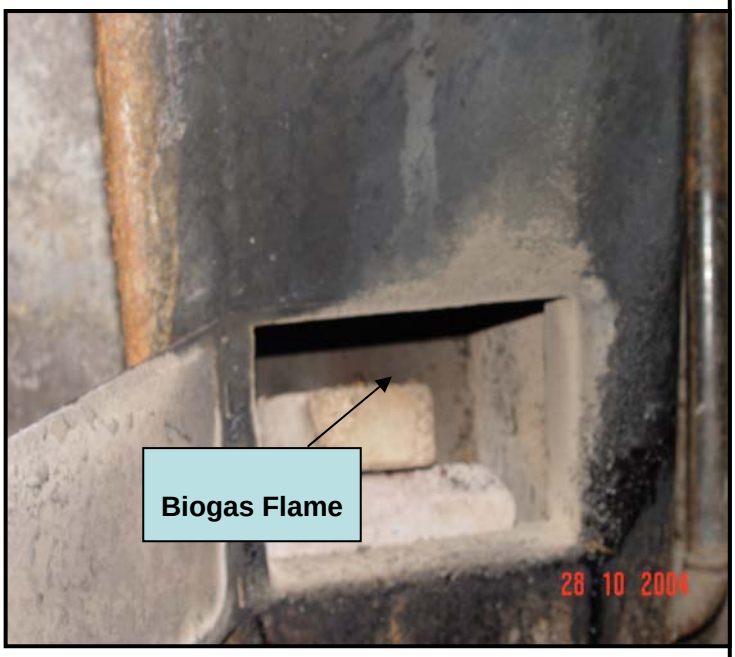
Figure B-8 Digester Pilot Plant at Losagart Bird Farm, A Division of Max Group

Anaerobic Digester and Gas Holding Tank

Chicken Waste Holding Tank



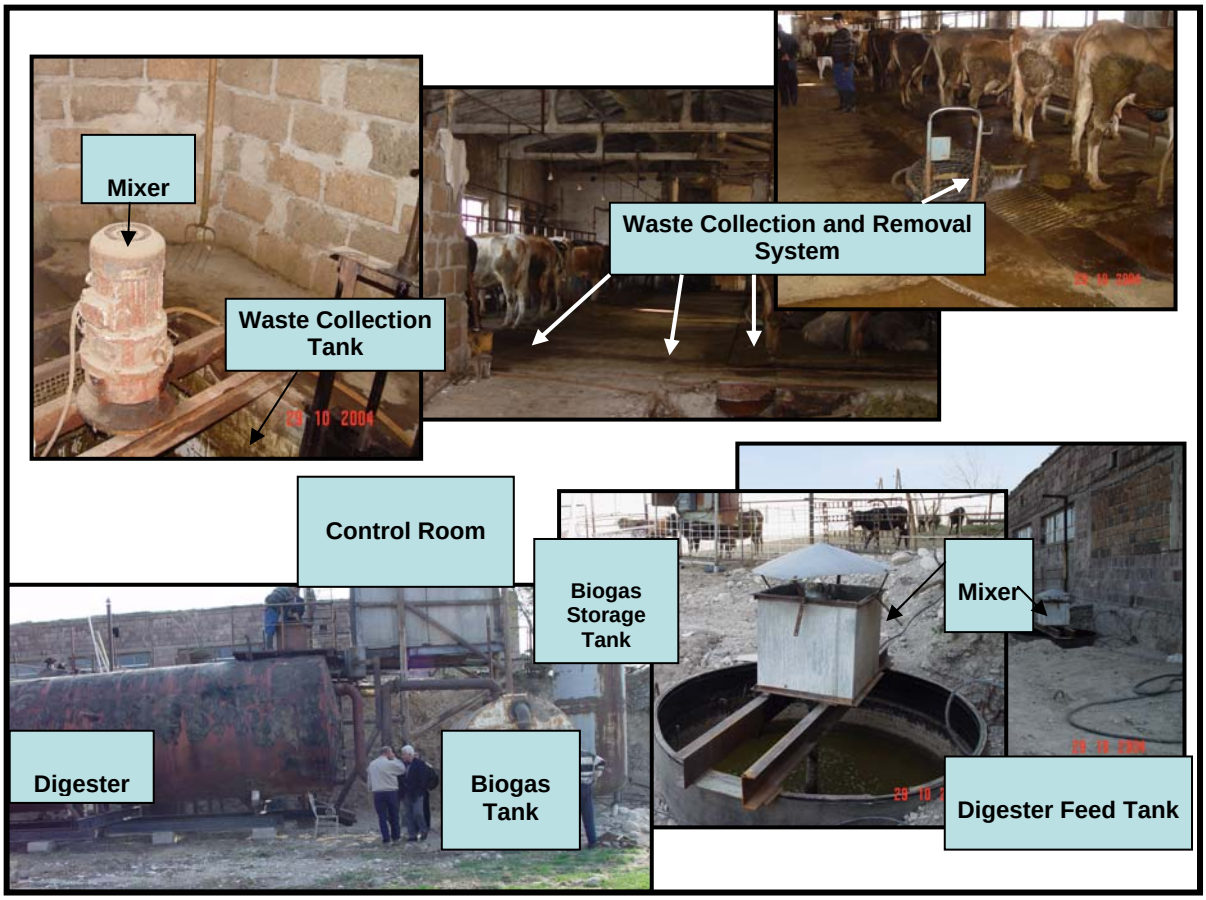
Solid Fertilizer Storage Area



Biogas Furnace

Figure B-9 Digester Pilot Plant at Agro Service Farm

Figure B.10 Digester Plant Under Construction at Black Ox Farm



3. GEOTHERMAL

As discussed in Section 5 of this report, earlier studies have identified numerous low temperature (cooler than 100°C) geothermal resources in Armenia. These earlier studies concluded that the location and extent of some resources should make them suitable for a variety of low-temperature applications such as space heating, greenhouse heating, other agricultural applications, and expanded recreational use. Some of these reports describe resorts and health facilities that have used geothermal resources for heating and recreational purposes, but the report also states that most of these facilities were closed or were operating at a much reduced capacity. More recent visits, by the consulting team, also found these geothermal facilities to be in disrepair and operating below design capacity. The hot water production and capacity of some of the wells, producing well below the projected capacity, may have been effected by the damage caused by earthquakes.

Regional heat flow studies, volcanic activities, and chemical geothermal investigations indicate that good geothermal resources exist in Armenia. High heat flow values of up to157 milliWatts per square meter (mW/m^2) have been estimated for 90 locations around Armenia[6]. The highest values were measured in the central part, where there are thermal springs. A substantial part of the heat flow anomaly has been found to be caused by local heat sources at shallow depth. Silica geothermometer estimates[7] of reservoir temperatures range from 40ºC to perhaps 160ºC. The eastern volcanic belt is thought to be the main area of geothermal potential where both dry and hydrothermal resources are expected.

The technologies for utilizing low and high temperature geothermal resources are well understood and are commercially available. Low temperature resources are used for direct or indirect heating in spas, agriculture (drying and greenhouses) industry, and heating of commercial and residential buildings. In some cases the geothermal fluid may go through a heat exchanger (water to water), where the heat is transferred to a secondary fluid. The load and the source should be in close proximity, or heat losses and piping expenses will make the project cost prohibitive. If an adequate resource exists, district heating systems may make sense. For example, four district heating systems in Boise, Idaho, USA withdraw approximately 2 billion liters of geothermal water per year to heat about 300 homes, government buildings, and businesses. A greenhouse application in New Mexico, USA, is shown in Figure B.11.

Electricity generation from geothermal energy requires a high temperature steam or hot water source (greater than 150 ºC) with sufficient flow capability to justify a power plant. Although power plants in the range of 5-10 MW have been built worldwide, the most economically feasible size is usually 50 MW or greater. Except in rare cases, surface manifestations provide little indication of the suitability of the geothermal resource, and exploration and development of a geothermal resources for power generation is costly.

To date, a viable commercial geothermal resource for power generation has not been identified in Armenia.

[6] M.Badalyan, Armenia Geophysical Institute, 2000 and J.W. Lund, US Geo-Heat Center, 2001
[7] Method of estimating underground water temperature based on the water silica content.

Figure B.11 A Greenhouse Utilizing Geothermal Heating, New Mexico, U.S.

Source: NREL

4. WIND POWER

Various studies have shown that Armenia has numerous sites with excellent potential for wind energy development. The Dutch government supported the identification, evaluation and prioritization of five potential sites, followed by a detailed wind measurement campaign and reporting[8]. A U.S. government-supported study, which was more comprehensive, employed digitized terrain data along with computational fluid dynamic modeling of the wind flow across the entire country. Wind models were tuned using long-term historical records from the Department of Hydrometeorology of the Republic of Armenia from 66 stations across the country, some dating back as far as the 1890s. In addition, the two commercial companies planning wind power projects in Armenia allowed the use of their proprietary wind databases from the high-quality measurement studies at 15 different sites. These data were an important ingredient in validating the wind modeling effort. The result was a "Wind Resource Atlas for Armenia"[9].

Princeton Energy Resources International, LLC (PERI) conducted an independent review of the input data and modeling methods used by the U.S. National Renewable Energy Laboratory for PA Consulting. The methods used in preparing the Atlas were found to be State Of The Art with reliable results. Similar analytical studies performed in the U.S. and other countries have proven to be accurate. In addition, results from the independent Dutch and U.S. studies and wind measurement programs were evaluated by PERI and were found to be consistent with the modeling results.

Armenia's best wind resource areas are generally located on higher ridges and mountains or in wind corridors such as mountain passes. Winds in Armenia are influenced by a mid-latitude westerly jet stream, a high-speed ribbon of air several kilometers above sea level that circles the globe and also affects the wind resource in North America and Asia. The jet stream is stronger and closer to the ground during winter months (October through March) due to a decrease in thermally induced mixing in the atmosphere. The jet stream also controls the progress of wind producing weather systems across Armenia and the Trans-Caucus region. This jet stream produces a seasonal wind pattern in Armenia with strongest winds in winter. This is consistent with the results of continuing wind measurement programs by the commercial wind plant developers, although some sites show peak periods in both summer and winter. These anomalies could not be explained from the available data but are likely due to the location of Armenian Weather Service measurement equipment. The Weather Service equipment are normally located in or near villages while the wind power plant sites are on open exposed terrain, such as the site shown in Figure B.12. Zod region is also influenced by wind flows from low elevation plains of the Caspian Sea region.

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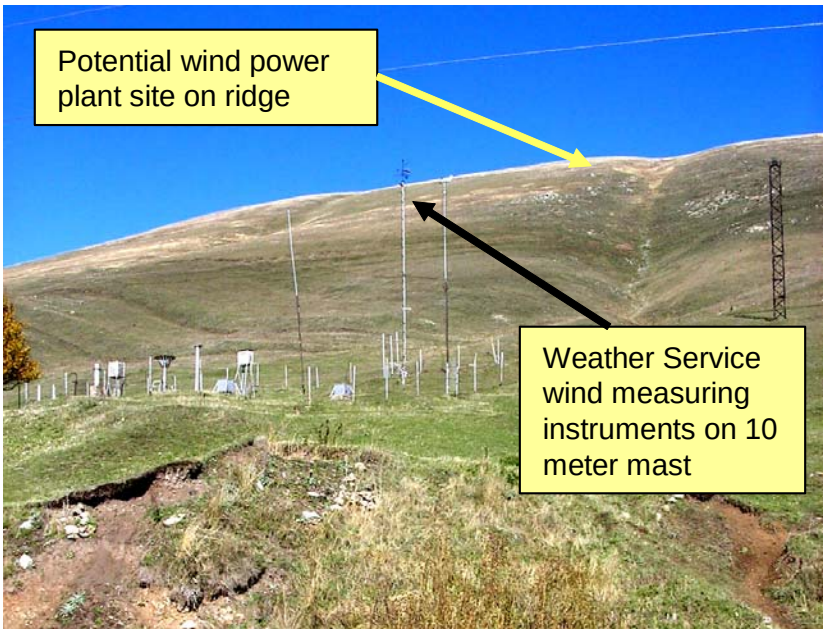
[8] Senter International, ARMNEDWIND Project, "Wind Resources Assessment Study," October 2000.

[9] D. Elliott, et al, U.S. Department of Energy, National Renewable Energy laboratory, "Wind Resource Atlas for Armenia," NREL/TP 500-33544, July 2003.

Figure B.12 Weather Service Station Shielded From Good Winds Near A Potential Wind Power Plant Site, Armenia



PERI's analysis indicates that it is likely that actual wind speeds may be substantially higher, particularly in the winter time, than current estimates indicate. Wind blockage at Weather Service stations is one potential factor, although this was considered in the preparation of the Wind Atlas. Another contributing factor is icing. Previous investigations at commercial wind power plant sites outside of Armenia indicate that icing of the anemometers (wind measurement instruments) is affecting the wind speed measurements. The first indication was found in examining detailed wind records during and after snow/icing events. Readings at the power plan sites were abnormally low, over 20% lower than the reference weather station sites that were at wind defilade locations. Also, the winter winds measured at the mountain sites were lower than would be expected for that location due to its terrain and synoptic weather patterns. Under certain atmospheric conditions, ice formations can develop that degrade instrument accuracy for days and even weeks following a snow or ice event. This occurs when temperatures are continually below freezing and there is no proper insulation, resulting in black ice formation on the sensors, which changes their aerodynamic properties and inertia. These conditions can cause incorrect, low readings. Icing of this type could result in significant underestimates of the wind resource in the winter months. Icing is not a problem unique to Armenia; similar difficulties face the wind industry in many countries with a climate similar to Armenia's. The problem can be simply solved by using special heated instruments for measurements in the future.

At least twelve potentially good to excellent wind resource areas covering about 1000 km^2 of land, in addition to large areas with moderate but usable wind resources, exist in Armenia. Nine areas, excluding Pushkin Pass, are identified as potential wind power plant sites. Wind resources are normally classified on a scale from 1-7, with Class 1and 2 having poor to marginal potentials. Class 3 areas are considered to have moderate potentials while Class 4 areas are considered as having good potential with average winds between 7.5 to 8.1 meters per second and an energy resources potential of 400-500 Watts per square meter of area swept by the turbine. Class 5-7 resources are considered as having excellent potential, containing 500-800 or more Watts per square meter.

Figure B.13 shows major wind resource areas in Armenia. The map shows the twelve resource areas and the nine potential sites mentioned above as well as larger regions with moderate (Class 3) wind resources. These areas could be developed and may be more accessible than some of the areas with highest wind resource, which are in the rugged and remote mountain areas. Mountain passes with expected high wind resources include Karakhach, Pushkin (where the first wind power plant in Armenia is being installed), and Jajur in the Bazum Range, Sevan and Ardanish in the Areguni Range, and Sisian in the Zangezur Range. The ridges around these passes are also predicted to have excellent wind resources. Mount Aragats and the Geghama Range have areas of good-to-excellent resource at 3000 m to 4000 m in elevation. The areas between Sisian and Goris have an estimated good-to-excellent resource. The elevations in this region are as low as 1800 m to 2000 m, and a major highway runs through the area. Finally, the Zod and the Megrhi regions serve as wind corridors allowing for accelerated wind flow from low elevation plains in the Caspian Sea region.

Figure B 13. Major Wind Resource Areas in Armenia

Figure B.14 Wind Resource Area Near Lake Sevan

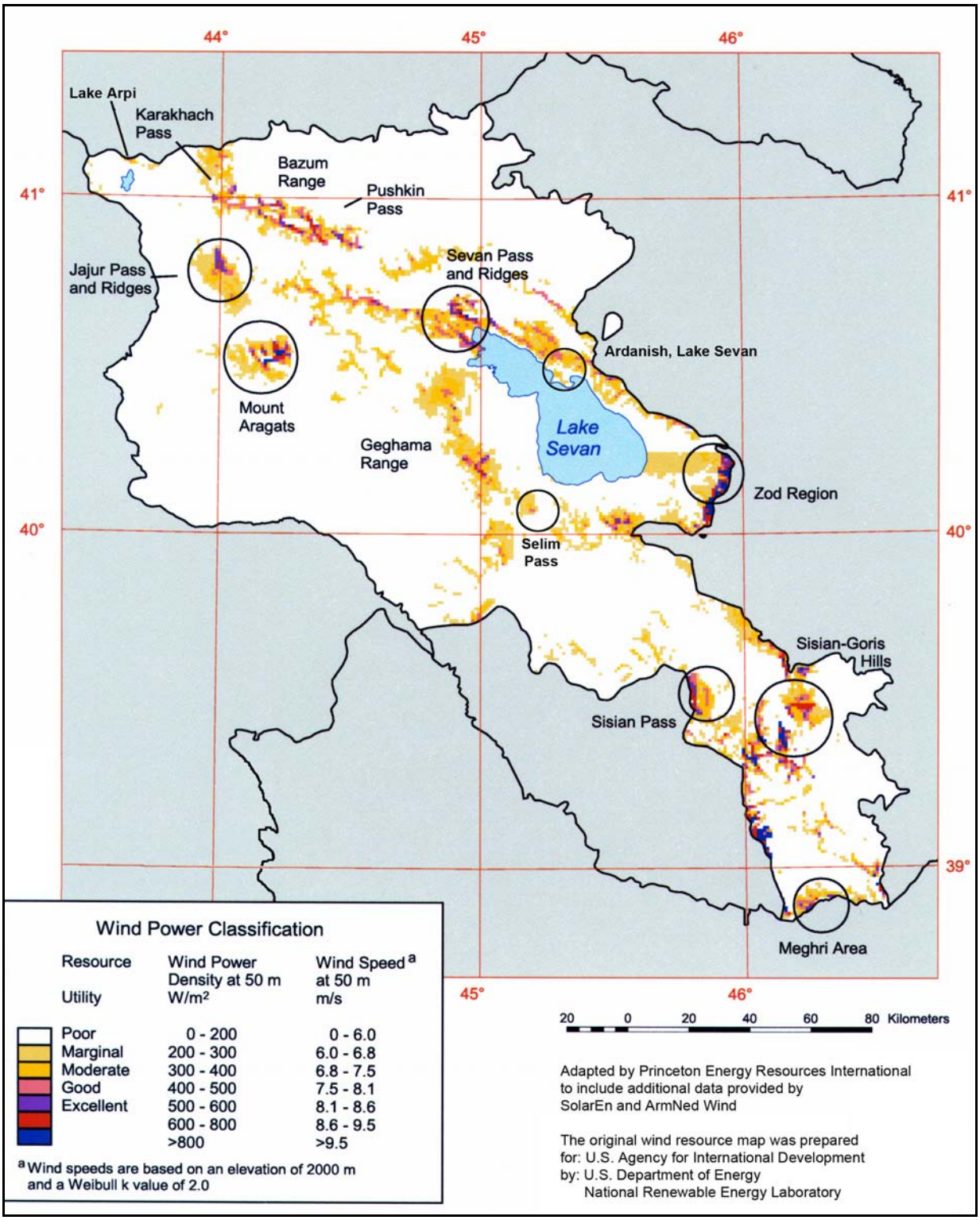


Figure B.14 shows the terrain for a potentially good wind power plant site, at a wind resource area identified in the Wind Atlas, near Lake Sevan.

The proportion of windy land (Class 3 and higher) and potential wind capacity in each wind power category is listed in Table B.1. This windy land represents less than 4% of the 28,400 km^2 of total land area of Armenia. Using a conservative assumption of 5 MW per square km, identified windy land could support almost 5,000 MW of potential installed capacity. If moderate, Class 3, wind areas were included, this resource potential increases to 11,000 MW. It is important to note that this is only an estimate of the gross resource potential and additional studies are needed to determine the economic viability of these potential sites considering factors such as proximity to the existing transmission grid, existing line loading, power demand profiles, transportation access, construction costs and others. If all potential sites could be developed, assuming a capacity factor of 30%, wind power could produce 13 billion kWh annually, more than twice the current National electricity generation.

Table B.1 Gross Wind Power Resource Potential [10]

Wind Resource Quality	Wind Class	Wind Power at 50 m (W/m^2)	Wind Speed at 50 m (m/s)	Wind Land Area (km^2)	Percent of Armenia n Land Area	Maximum Capacity Potential (MW)
Moderate	3	300 - 400	6.8 - 7.5	1,226	4.3	6,150
Good	4	400 - 500	7.5 - 8.1	503	1.8	2,500
Excellent	5	500 - 600	8.1 - 8.6	208	0.7	1,050
Excellent	6	600 - 800	8.6 - 9.5	165	0.6	850
Excellent	7+	>800	>9.5	103	0.4	500
Total				2,205	7.8	11,050

The large areas with moderate winds could be suitable for future development using “Low Wind Speed Turbines” that are currently being developed. These new machines have larger rotors, improved low speed aerodynamic performance and more efficient drive systems, and are now being deployed in the U.S. and Europe.

Integrating the operation of large-scale wind power plants with existing hydropower plants could also provide significant technical and economical benefits to Armenia. Both hydro and wind are resources controlled by nature and are consequently somewhat unpredictable. Although these two energy sources are variable, there appears to be a symbiotic relationship between the two sources in many locations. The benefits of combined wind and hydro resources are just now beginning to be recognized in the U.S., Europe, and Russia. In a study of the power system in the State of Vermont, USA, PERI found that by integrating the potential wind power output (up to 810 MW by 2010) from Vermont with the hydro-based system operated by Hydro-Québec in Canada, the market value of wind could increase by up to 22% if the wind energy was exported to Québec during winter periods of peak demand rather than being sold at spot market prices. In addition, the study showed that wind plants could also alleviate operating limitations and constraints on Canadian hydro plants by providing energy during winter months when river flows are lowest but wind power output in Vermont would be at its highest.

PERI also evaluated the wind-hydro concept, which was modeled in detail for the U.S.-Canadian case, for a project in Northwest Russia. With support from USTDA and the Global Environmental Facility of the World Bank, PERI conducted a feasibility study for a

[10] D. Elliott, et al, U.S. Department of Energy, National Renewable Energy laboratory, “Wind Resource Atlas for Armenia,” NREL/TP 500-33544, July 2003.

75 MW wind power plant planned in Leningrad Oblast. This study showed benefits of similar wind-hydro plants, including improved seasonal and annual hydropower plant operation and energy production, as well as providing water resource management benefits.

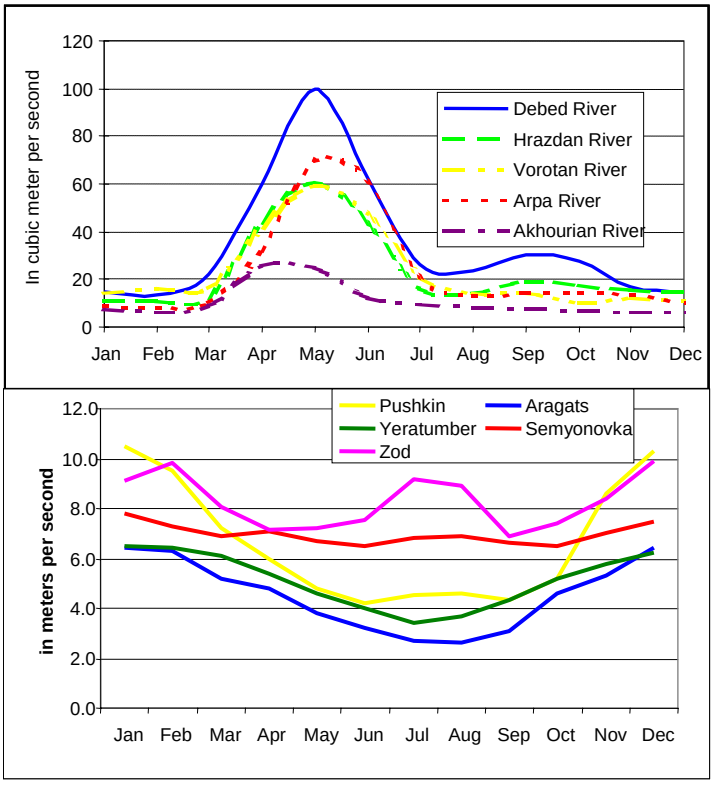
In Denmark, there are periods when the output from the wind plants on the Jutland Peninsula exceeds the regional demand. Excess power is exported to Norway where hydropower generation can be supplanted by wind power, thus in effect “storing” the wind energy in the form of unused water. This energy is then returned to Denmark days or even months later, during low wind periods.

In Armenia there is an indication that wind and hydropower will work well together and may help improve the economic value of both energy sources. River flow and consequently, hydropower production varies widely, both seasonally and annually. However, available data indicates that wind and hydro resources are complementary to each other as shown in Figure B.15.

Figure B.15 shows the seasonal variation in flow rates of five major rivers and average monthly wind speeds at five different areas in Armenia. The water flows are low in winter time when the wind speeds are high. What is not shown in Figure D.14 is that the electric demand also peaks in winter time. During the spring season when water flow rates increase, the wind speeds drop. In summer, both water flows and wind speeds are generally lower, although the wind speed at some locations, particularly at Zod, moderately peaks. This secondary peak in the wind resource coincides with critically needed electricity for irrigation pumping (currently about 42% of the irrigation water is pumped as opposed to gravity flow). In late summer and fall, wind speeds begin to pick-up again.

The following discussion further illustrates the potential benefit of wind-hydro integration in Armenia. About 1,023 MW of installed hydro plant capacity produced over 1.2 billion kWh during year 2000. If five 100 MW wind power plants were constructed (assuming economically feasible), one at each of sites listed in Figure B.15, the combined wind resources could produce about 1.3 billion kWh of electricity annually. This estimate is based on the actual 1999 monthly wind profiles for the five sites, assuming an average capacity factor of 30%.

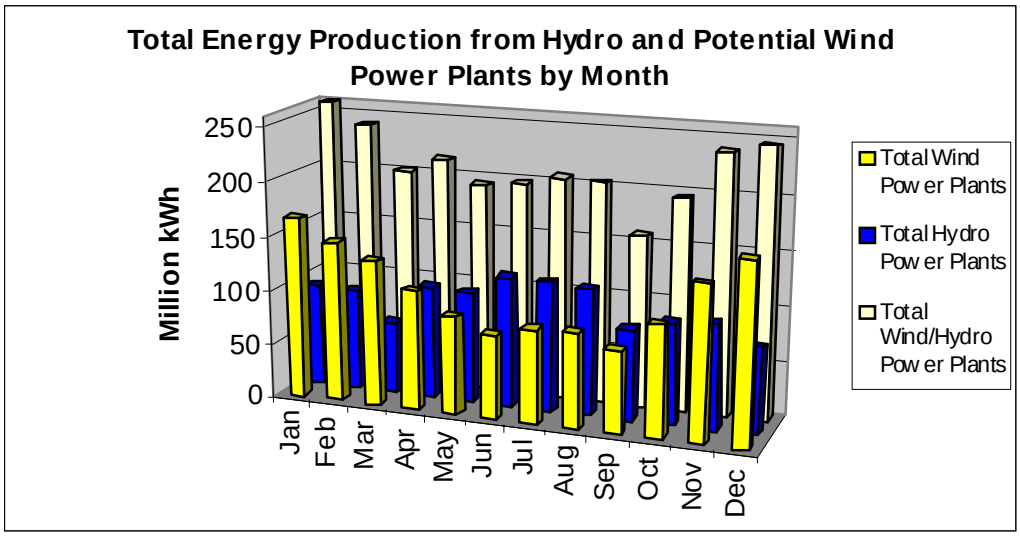
Figure B.15 Monthly Comparison of Wind and Hydro Resources



Sources: World Bank, SolarEn, AemNedWind and NREL

The estimated monthly wind power production is shown in Figure B.16 along with actual monthly electricity production from all hydro plants in the same year. As expected, Figure B.16 shows that in winter months and late fall when hydro generation drops, wind power generation increases. It also shows that while the total monthly potential generation, for wind-hydro, exceeds 220 million kWh in January, February, November, and December, the wind and hydro generation for the other months would total about 200 million kWh per months, except September. Dispatching wind plants on a priority basis and curtailing hydro production during high wind periods, provided sufficient storage capacity exists at existing dams and reservoirs, could yield an increase in firm available wind-hydro capacity and maximize utilization of water for power generation and agricultural purposes.

Figure B.16 Monthly Potential Wind- and Hydro-power Generation



The hydropower system in Armenia includes extensive reservoirs that could potentially be used for saving water during windy periods by curtailing hydro generation. The country has 79 dams with a total capacity of 1.1 billion cubic meters (BCM). Seventy reservoirs are used for irrigation, six exclusively for hydropower generation, and three are for dual use.

Further detailed analysis is needed to determine economic value of wind–hydropower integration for providing a firm wind-hydro capacity. Wind power plants could provide support for hydropower system and vice versa.

APPENDIX C:

Capital Structure of the Electric Sector Companies

Armenian Power Sector 2006 Least Cost Generation Plan

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1. APPENDIX C: CAPITAL STRUCTURE OF THE ELECTRIC SECTOR COMPANIES

Analysis of capital structure of energy companies operating in the electric power sector of Armenia indicate a wide range of potential options: from 100% equity, the cases of which can be found among both state-owned and private sector enterprises, to 100% debt financed enterprises, examples of the latter can be found only among state owned enterprises. Table C.1 describes structure of capital for major electric power companies calculated on the basis of their 2004 balance sheets, as submitted to the Public Services Regulatory Commission.

Table C.1 Capital Structure of Armenia Electrical Power Companies

Company Name	Capital Structure	
	2003	**2004**
Yerevan CHP		
Share of Equity Capital	60%	7%
Share of Debt	40%	93%
Vorotan HPP		
Share of Equity Capital	99%	98%
Share of Debt	1%	2%
Hrazdan TPP		
Share of Equity Capital	N/a	100%
Share of Debt	N/a	0%
Medzamor NPP		
Share of Equity Capital	-3%[1]	59%
Share of Debt	103%	41%
International Energy Corporation (Sevan-Hrazdan HPP)		
Share of Equity Capital	1%	25%
Share of Debt	99%	75%
High Voltage Networks		
Share of Equity Capital	71%	55%
Share of Debt	28%	45%
ElNetArm (Distribution Networks)		
Share of Equity Capital	94%	97%
Share of Debt	6%	3%

It is worth noting, that Public Service Regulatory Commission in its rate setting cases utilizes different amounts for Cost of Equity, depending on the company ownership; for the state-owned companies it is normal regulatory practice to set up tariffs on the basis of 1-2% of weighted average cost of capital (after tax), while for the private owners it is set at 17%.

[1] As indicated in the official balance sheet.

APPENDIX D:

Electricity Demand Forecast

Armenian Power Sector 2006 Least Cost Generation Plan

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Attachments to Appendix D:

Appendices

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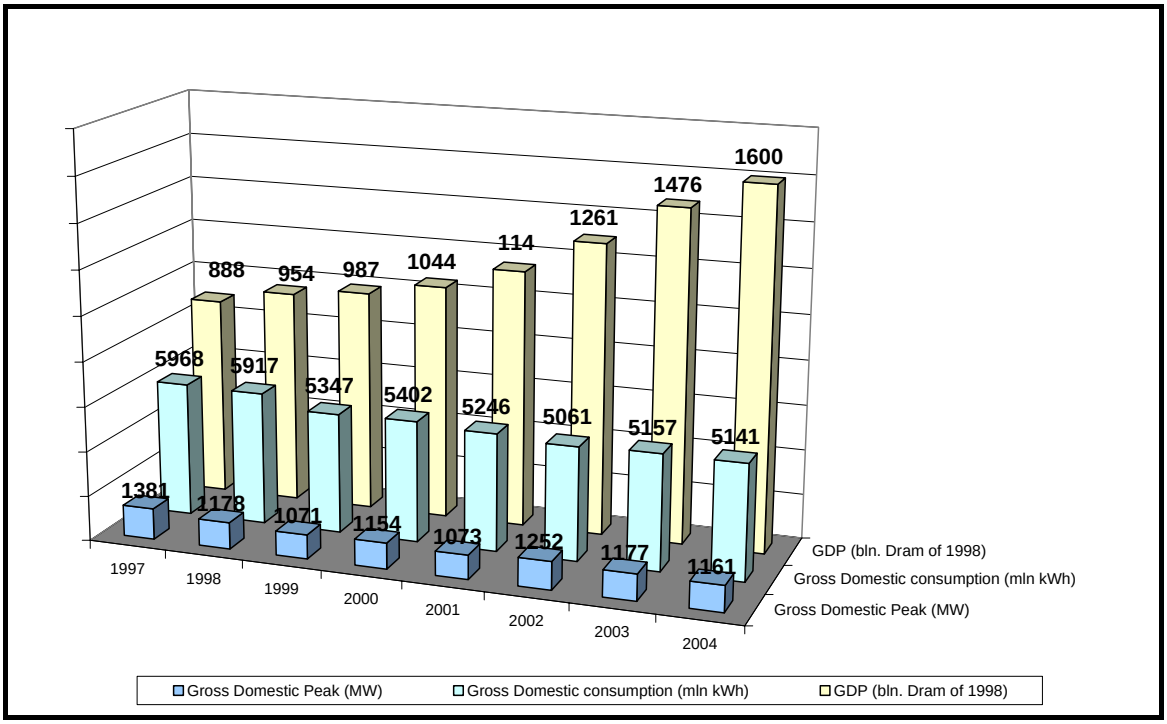
Annex B:	**Calculation of Growth Rates for Recent Trends in Consumption**	**B-1**

1. ECONOMIC DEVELOPMENT AND ENERGY CONSUMPTION

Recent trends in economic development and energy consumption are presented in Figure D.1. The graph depicts the changes in Armenian gross domestic product against domestic electric power consumption and system peak loads, which were observed over 1997-2004. GDP is presented in constant money, billion Drams of 1998, to facilitate the comparison. Domestic electric power consumption and system peak loads are expressed in million kWh and MW respectively.

Figure D.1 clearly shows that there is no direct and positive correlation between the level of economic production in the country and electricity consumption over this period. This Figure also illustrates the complexity of forecasting energy demand as a function of economic growth under current economic conditions in Armenia.

Figure D.1. Economic Development and Energy consumption



A major contributing factor to this complexity is the poor quality of the economic and energy statistics in Armenia. Currently, there is also a tendency to overweigh positive trends in electricity consumption which causes over estimation of forecasted energy demand. The trend observed in Figure D.1 may be attributed, for example, to continuing immigration out of the country, which can result in observed relative reduction in electricity consumption, considering the dominating share of electricity consumption in the residential sector. Another potential explanation is replacement of electrical heaters with gas or other types of heaters. Though, an in-depth analysis of a complex relationship between GDP and electric power consumption is beyond the scope of this study, several reasons explaining observed phenomenon are discussed below.

Figure D.2. Quarterly GDP, 1999 - 2004.

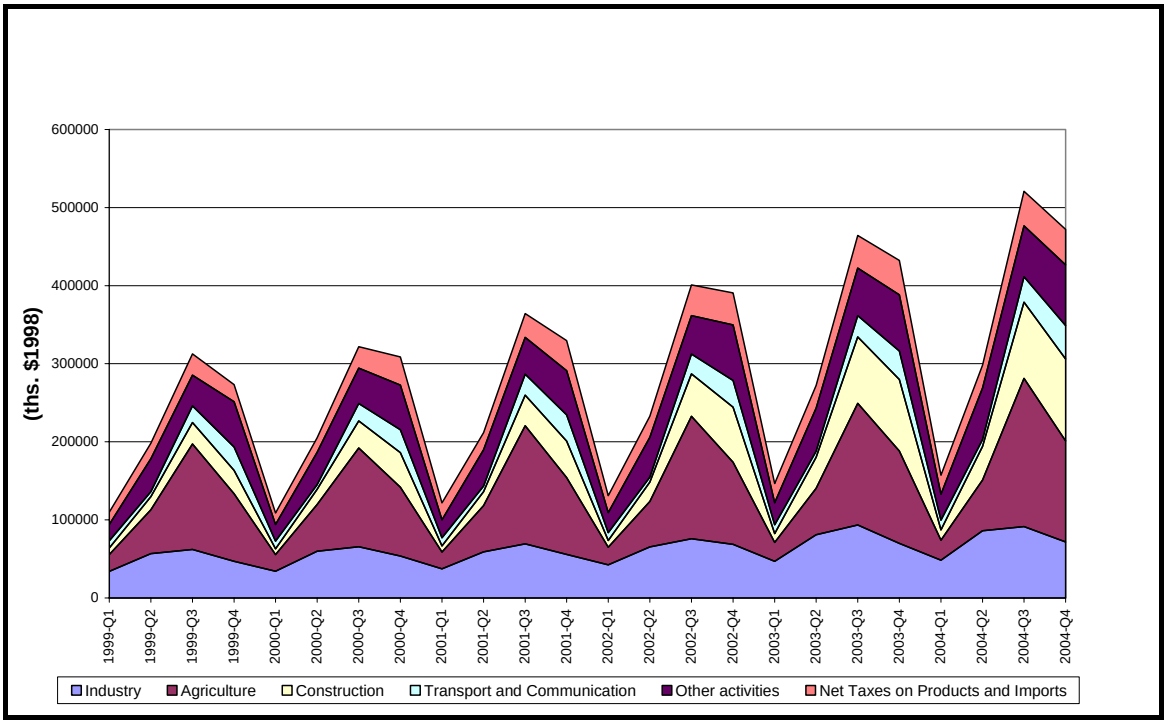


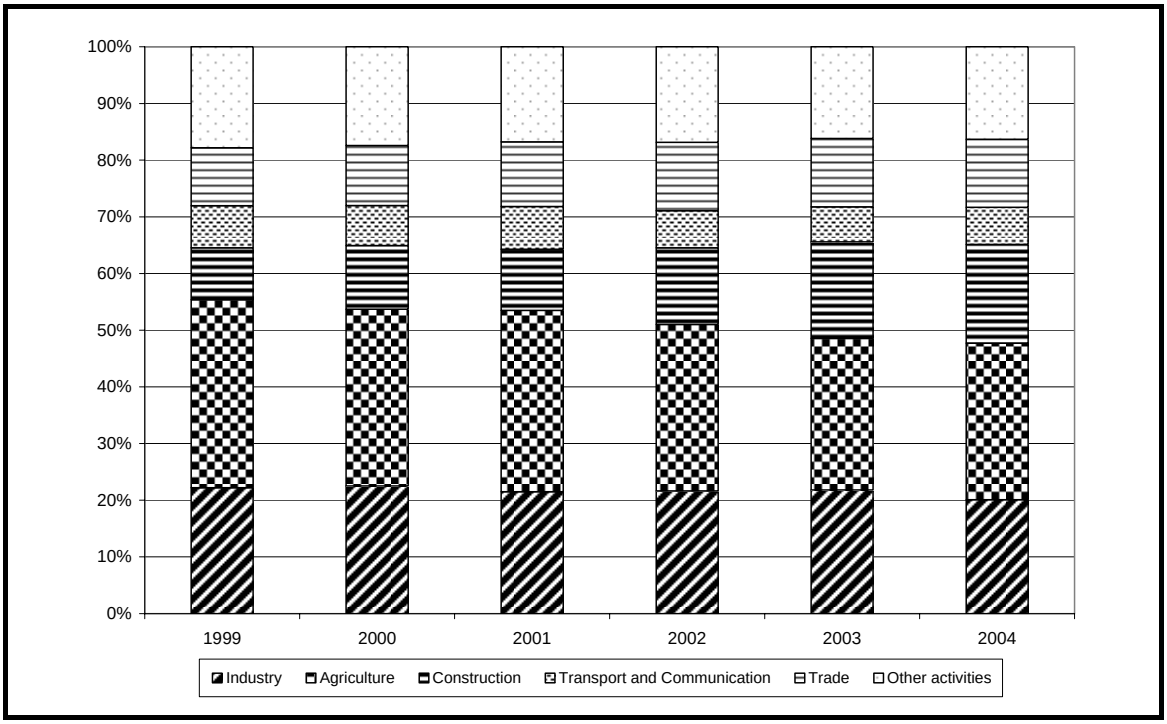
Figure D.2 shows that between 1999 and 2004, in Armenian economy, a major growth occurred in agriculture and construction industry. To somewhat lesser extent, the production of GDP grew in a sector generically referred to as “other activities”, which represents the services and commercial sectors. Industrial growth was next, with major growth taking place between 2002 and 2003, and remaining the same in 2003 and 2004.

The aforementioned growth pattern has changed the structure of national economy (Figure D.3). The share of agricultural and industrial production dropped from 30% to 25% and from 20% to 18% respectively. During the same period the shares of the transport and communication, and other activities sectors remained constant (between 7% and 6% and between 16% and 15% respectively) while, the share of construction in GDP doubled from 8% to 16% and the share of trade grew from 9% to 11%. These figures demonstrate that the structure of Armenian economy has started changing toward less electric power intensive sectors.

The other obvious reason, which should be mentioned, is that the energy intensity of new enterprises coming on line is lower than that of existing enterprises, since they are based on new, more energy efficient technologies. Therefore, the aggregate energy intensity of each sector of economy is reduced, which along with the structural changes lead to overall reduction in consumption of electricity per unit of GDP.

It could be argued that it would be impossible or erroneous to accept that there is no growth in consumption of electric power in Armenia over the considered period. This may be partially true but as Figure D.4 illustrates reduction in commercial losses have been greater than any growth in demand, causing the effective electric power demand change insignificant between 1999 and 2004.

Figure D.3. Changing Structure of Armenia Economy (Based on GDP in $1998)



Effective power demand is the sum of electric power supplied to distribution networks and commercial losses. It is this sum that represents total consumed electricity, which consists of a paid (metered consumption), commercial losses and technical losses. Distribution networks technical losses are included in electric power supplied to distribution networks.

Since 2002, when distribution company was privatized, the new owners made it their goal to reduce commercial losses. However, given the lack of precise information on customer base changes (such as a number of existing and new customers and individual customer consumption statistics) it is impossible to estimate what portion of the growth in effective consumption was due to administrative measures and what was caused by economic growth.

The causes for such a low growth in electric power consumption against the recent impressive economic achievements can also be explained by more detailed review of statistics of electric power consumption by customer type. Figure D.5 presents actual monthly statistics on electric power sales.

Figure D.4. Effective Electric Power Demand for and Economic Development

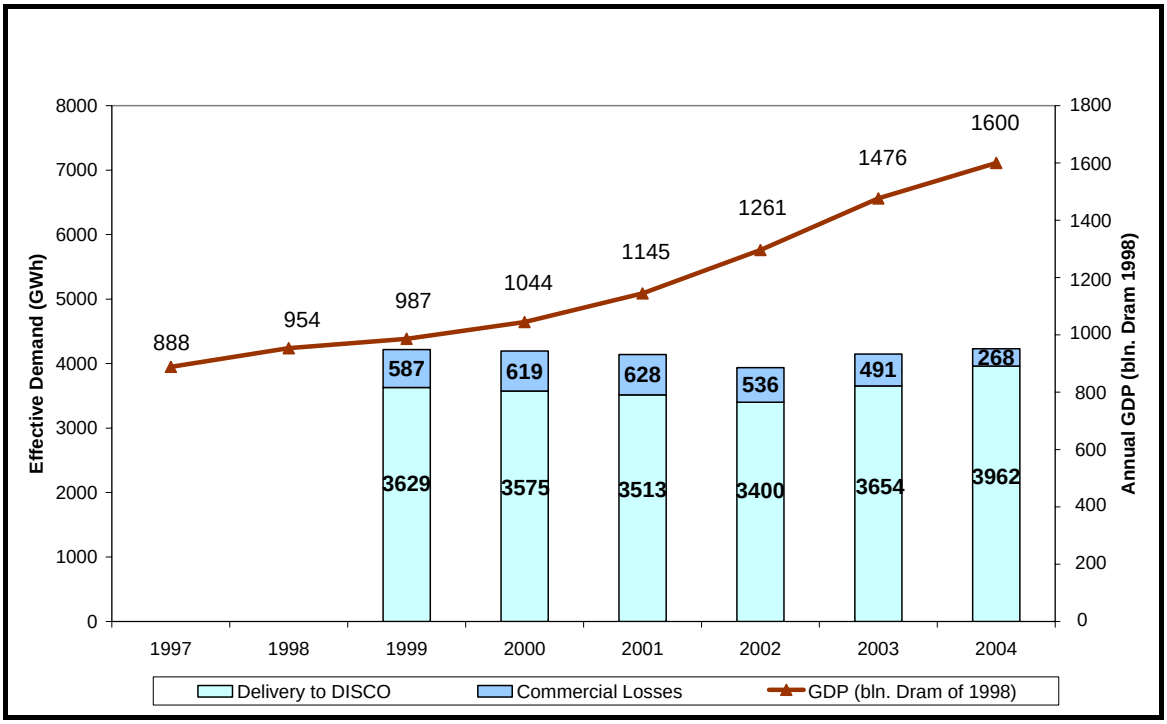


Figure D.5. Monthly Electric Power Sales

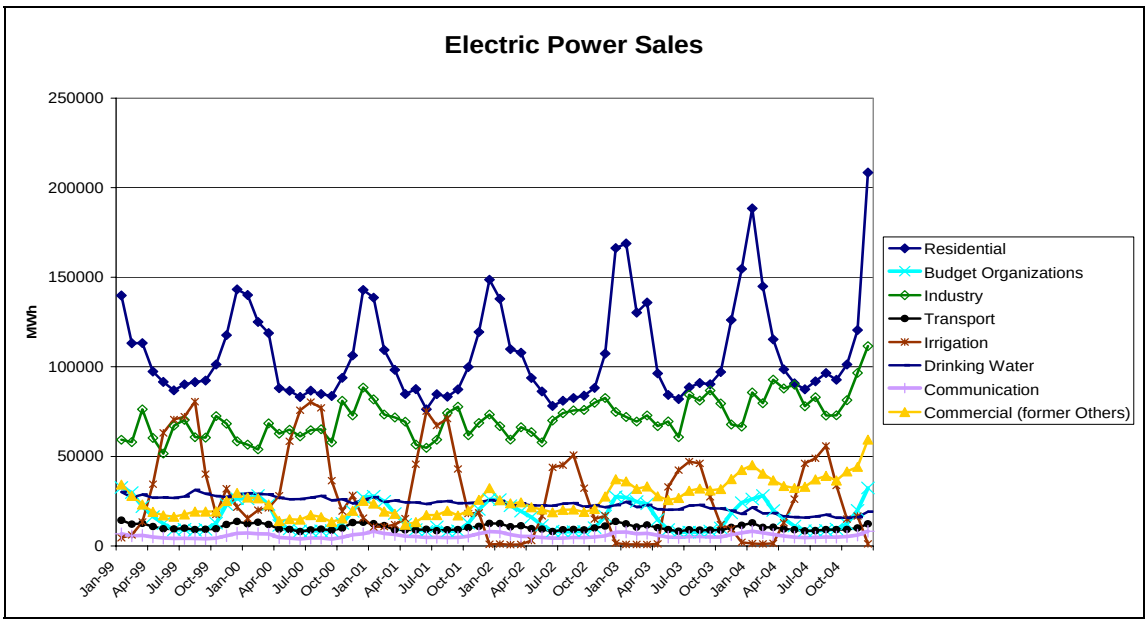


Figure D.5 clearly illustrates that significant growth in monthly electric power sales has occurred in residential and commercial sector[1]. The sales of electric power also grew in industrial sector, although its overall pattern has been more sporadic and less predictable (see Annex A.1 for industrial growth without its principal growing segments as reference).

[1] Though there is no such category as commercial sector in the statistics currently maintained by ElNetArm, the customer categories were regrouped to single out this customer category.

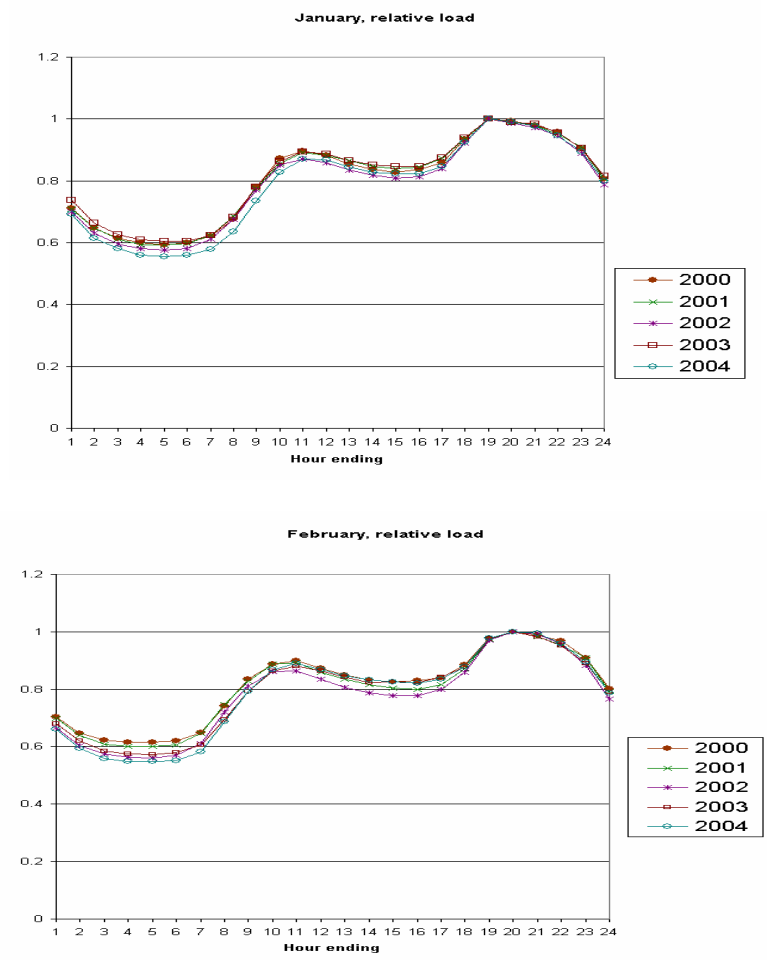
During the same period, the electric power consumption in drinking water and irrigation has been steadily declining, followed by smaller reduction in transport. Consumption in communication practically remained unchanged and insignificant growth was observed in budget organizations. Therefore, the information confirms that the growth has occurred in less energy intensive sectors (commercial and budget organizations), and to a lesser extent in the industrial sector, and the highest growth has been in the residential sector. However, for residential sector, it is unclear if the growth was due to the rise of the sectors disposable income or reduction in commercial losses.

2. CHANGES IN SYSTEM LOAD SHAPE

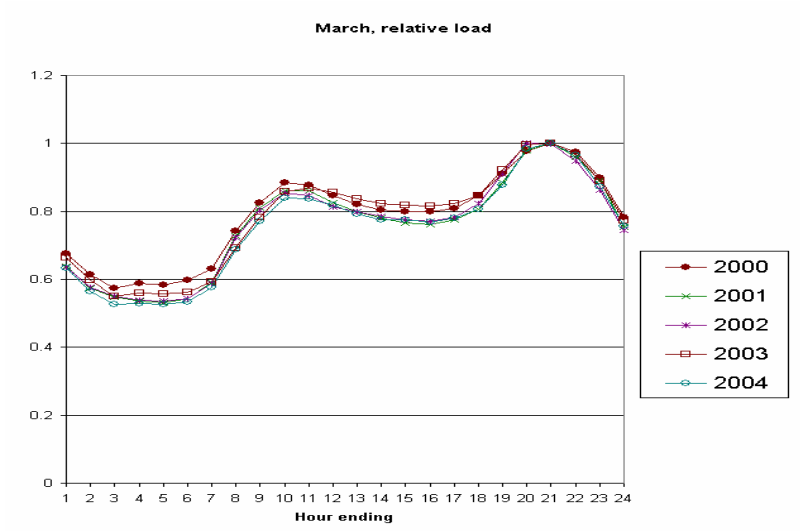
Despite the changes in the amount of consumed electricity, the consumption pattern remained stable over the period under consideration. Typical hourly load curves, by month, are presented in Figure D.6. These were derived from average hourly loads, based on actual hourly generation, dispatched during 2000-2004 for domestic needs, per system dispatcher's logs. To facilitate easier comparisons of load shapes, the hourly loads were divided by the maximum daily consumption, which resulted in a variation of hourly values between zero and one. This transformation simplifies the relative comparison of load shapes, since it eliminates the amounts expressed in absolute numbers.

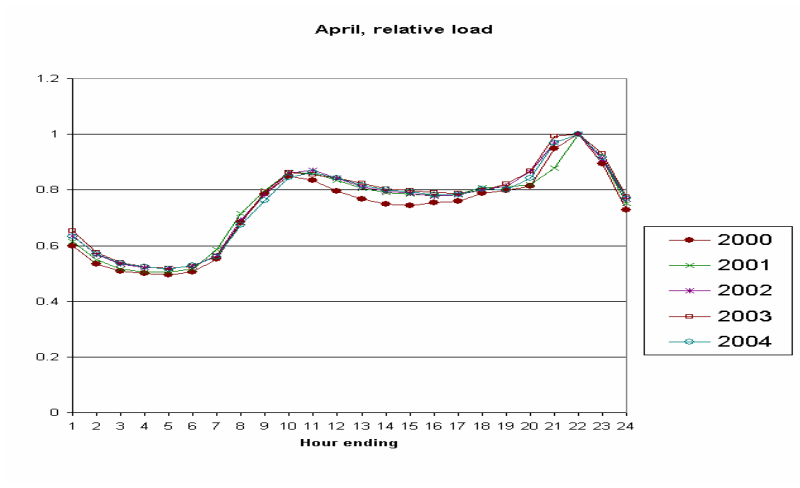
A comparison of 2000 - 2004 load shapes with those published earlier (LCGP 2000 and 2002) indicates that no profound changes in system load shape have occurred. For each individual month the shape of the system load remains extremely stable. The load shapes exhibit typical features of the load that is specific to a system with predominant residential load – they have two distinct peaks, and reduction in the morning peak, as people leave home for work at about 9-10 a.m., is not offset by the load increase in other sectors. The changes in load shapes in different years are not due to a stable long-term change in consumption patterns, but to weather conditions.

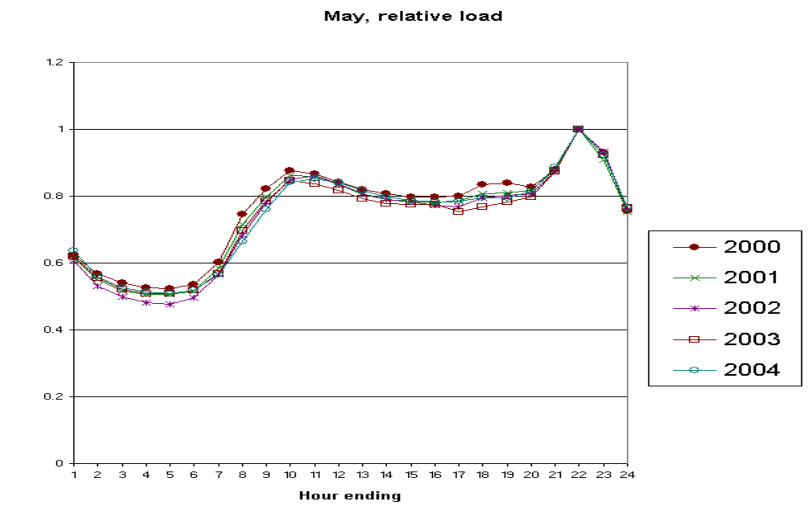
Figure D.6. Typical load curves for 2000-2004.



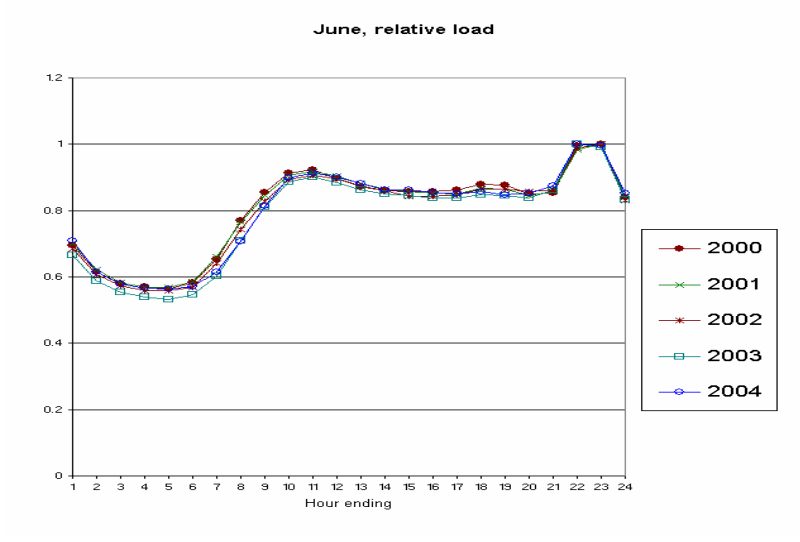
2. Changes in System Load Shape

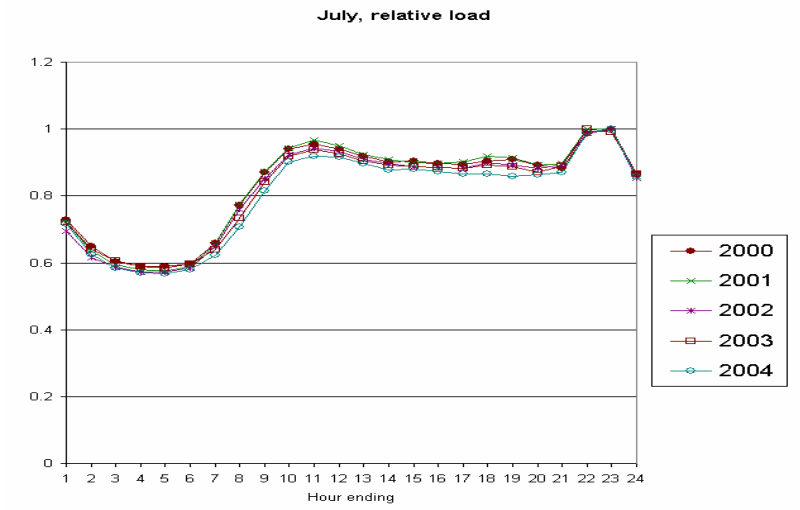


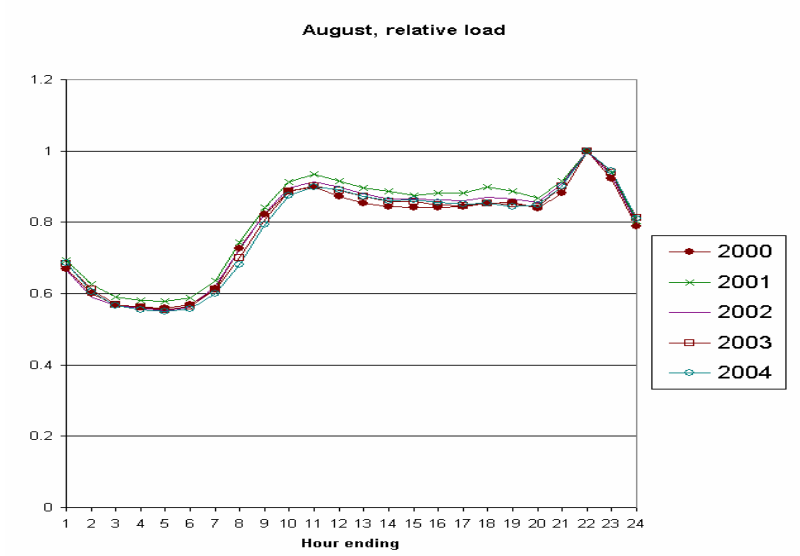




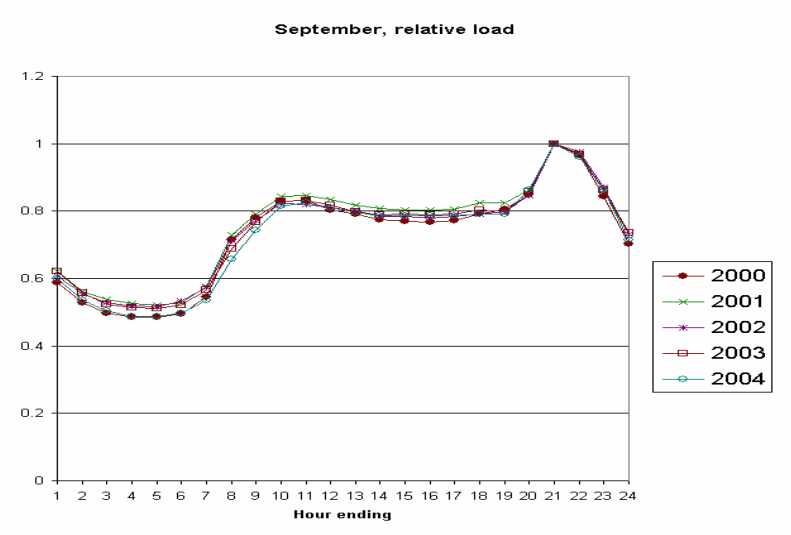
2. Changes in System Load Shape

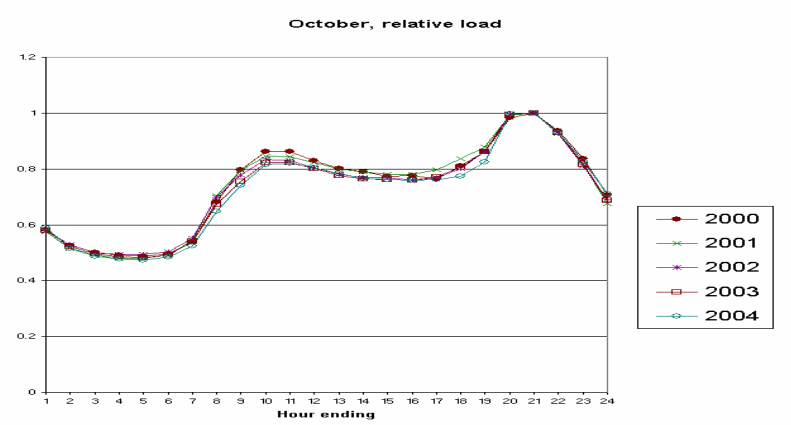


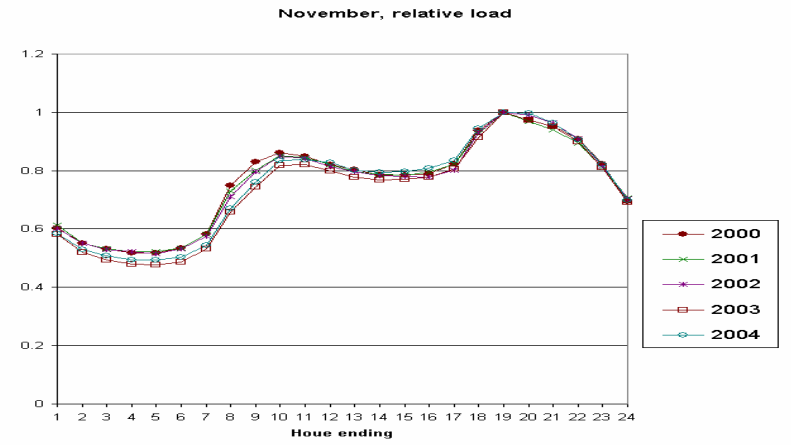


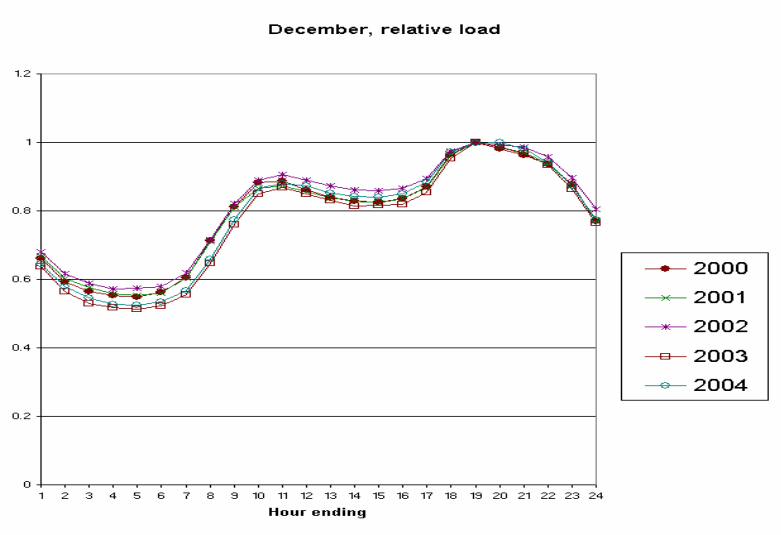


2. Changes in System Load Shape









Statistical data, from the dispatch log of National Dispatch Center, representing technical operation of the system between 1998 and 2004 are presented in tables D.1, D.2 and D.3. The presented statistics may not exactly match the data obtained from the commercial metering system of Settlement Center. The system of commercial metering and data acquisition in the power sector was launched in 2002, and in principle, the data from this system is more accurate. However, for comparability analysis, consistent with previous LCGPs, dispatch log data was used.

Table D.1. Armenia's Gross Electric Power Generation for Internal Needs (MWh) [2]

	1998	1999	2000	2001	2002	2003	2004
January	674814	565944	560846	595455	552944	591731	556412
February	600168	475433	538442	496009	448533	493224	497931
March	571089	487366	515544	432513	431886	502511	431120
April	410086	409185	364849	359452	376438	368398	382547
May	402313	409313	411043	369845	255215	257418	270442
June	404802	405747	402194	378111	359041	404802	405747
July	433546	417874	419344	401029	375864	433546	417874
August	413531	419323	403066	418868	387840	397155	391158
September	388162	361377	350742	390202	362670	376423	355128
October	409713	377388	389745	383523	378738	366897	373024
November	477282	477487	461072	480885	443398	433222	437083
December	554994	553582	585698.8	555705	598759	538116	600906
Total	5740500	5360019	5402586	5261597	4971326	5163444	5119372

[2]) Note: The data from dispatch log never matched with the official commercial information. There is significant difference between the two sources of data for 1998.

Table D.2. Peak Load of Armenia's Domestic Market (MW)[2]

	1998	1999	2000	2001	2002	2003	2004
January	1183	1017	1031	1073	1032	1078	1011
February	1233	947	1028	992	921	969	992
March	1105	908	976	837	827	965	883
April	936	833	791	736	767	854	848
May	856	806	794	728	683	681	704
June	768	749	745	707	678	659	695
July	756	746	740	728	662	695	687
August	770	785	751	769	698	770	743
September	834	771	733	767	738	754	710
October	882	957	816	862	788	745	764
November	949	953	943	1006	862	926	930
December	1178	1071	1154	1010	1252	1177	1161

Table D.3 shows that in the last two years, the average annual load factor has stabilized and remained at about 50%. It also shows that load factors were about 53% and 57% in 1998 and 1999 respectively. Although to a large extent these changes are weather related, they demonstrate a potential for future changes in load factor (i.e.; demand), should development in the industrial sector increase to its earlier levels. The load factor for 2002 is lower than expected due to severe weather conditions, which caused system failures, resulting in a 5% drop in annual load factor as compared with 2003 and 2004.

Table D.3. Average Monthly and Annual Load Factors[2]

	1998	1999	2000	2001	2002	2003	2004
January	76.7%	74.8%	73.1%	74.6%	72.0%	73.8%	74.0%
February	72.4%	74.7%	75.3%	74.4%	72.5%	75.7%	72.1%
March	69.5%	72.1%	71.0%	69.5%	70.2%	70.0%	65.6%
April	60.9%	68.2%	64.1%	67.8%	68.2%	59.9%	62.7%
May	63.2%	68.3%	69.6%	68.3%	50.2%	50.8%	51.6%
June	73.2%	75.2%	75.0%	74.3%	73.5%	85.3%	81.1%
July	77.1%	75.3%	76.2%	74.0%	76.3%	83.9%	81.8%
August	72.2%	71.8%	72.1%	73.2%	74.7%	69.3%	70.8%
September	64.6%	65.1%	66.5%	70.7%	68.3%	69.3%	69.5%
October	62.4%	53.0%	64.2%	59.8%	64.6%	66.2%	65.6%
November	69.9%	69.6%	67.9%	66.4%	71.4%	65.0%	65.3%
December	63.3%	69.5%	68.2%	74.0%	64.3%	61.5%	69.6%
Annual LF	53.1%	57.1%	53.3%	56.0%	45.3%	50.1%	50.2%

The data shown in tables D.1 through D.3 is also consistent with previous LCGPs base-case load forecasts, which stated that Armenia's electric sector would experience a reduction in annual load factor[3] in the future due increasing share of less energy intensive sectors of economy (mainly, by commercial customers).

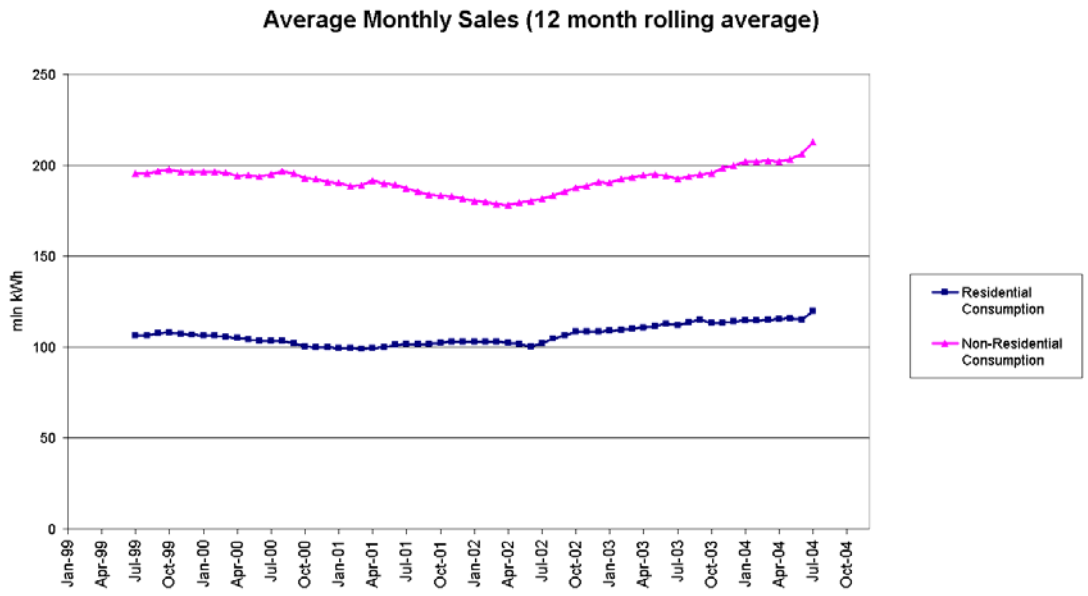
[3]) Average Load Factor over a period of time is calculated as LF = Energy/(Max Load*Period Duration) and shows the percentage of average load over the period compared with the maximum load observed over the same period.

3. RECENT TRENDS IN ELECTRIC POWER CONSUMPTION

Figure D.7 clearly demonstrates that, over the past 3 years, the trend for electric power consumption in Armenia has changed. This Figure presents 12 month rolling averages calculated for monthly sales to residential sector and all other sectors collectively using monthly sales data by the distribution company. The database, maintained at the distribution company, covers the period from January 1999 through December 2004.

Calculation of 12 month rolling average allows elimination of variations caused by differences in weather conditions and for this reason can be used as a good tool to identify and illustrate long-term trends. This Figure shows that the 1999 to 2004 can be divided into two distinctively different periods, a period of declining sales, which lasted until April – July 2002, followed by a period of growing sales. This information was used to estimate average growth rate in consumption in the sector since 1999. The estimated average growth rate is about 5% for aggregated non-residential sector and about 6% for residential sector. These rates are used as a benchmark to develop future scenarios for electric power demand in Armenia for LCGP 2005. Detailed calculations for developing these estimates are presented in Annex B.

Figure D.7. Recent trends in consumption of electric power in Armenia



4. FORECASTING APPROACH/ METHODOLOGY

A new approach was used for modeling future consumption of electric power for the LCGP 2005, as compared with approach used for previous LCGPs. For previous studies a model was developed to simulate future development of electric power sales.

The 2000 modeling effort was intended to derive the relationship between potential development of GDP and electric power consumption. The simulation algorithm varied for different types of consumers of electric power. Consumption by non-residential customers was modeled via potential changes in energy intensity[4] in each sub-sector of economy. Residential sector was modeled on the basis of end-use approach and changes in energy efficiency of electric appliances, penetration rate on the market, and behavior pattern. The model also attempted to assess future development of GDP as a function of investment level, outstanding external debt of Armenia, and private transfers, which substantially effected overall economic situation.

Special attention was given to the modeling the changes in the system load shape and its future evolution. The forecasts were based on the information on electric appliances in residential sector and generic load shapes for each class of customers and type of industry, which were taken from the guidelines to electric power system modeling, used during the Soviet times. Though, overall results of modeling proved to be accurate enough as was confirmed by later development of the electric power sector in Armenia, the very foundation of the overall approach suffered from a lack of accurate and reliable information. The most prominent deficiency pertained to the modeling of the system load shape, which drives future requirements in the amounts and types of generation technologies.

The approach for modeling the LCGP 2002 demand forecast was based on a different model, but contrary to the 2000 study, the model attempted to determine the trends based on actual consumption for different customer groups, as well as the trends exhibited in electrical losses.

The results of forecasting in both cases turned out to be very accurate, however this accuracy was not necessarily due to the quality of models used or the approaches taken, but rather political independence.

In October 2002, the Distribution Company was privatized. This event increased the level of complexity for modeling, because upon privatization the company unveiled a new campaign aimed at reducing commercial losses. The results were positive and the overall situation in the sector was improved. But, it added new complicating factors to forecasting. Currently, due to lack of data, it is impossible to differentiate if the changes in electrical demand were caused by improved economy of the country, improved management practices of the Distribution Company, or a reduction in commercial losses.

Furthermore, other issues which were raised in the previous editions of least cost generation plans have remained unanswered. In particular:

- Absence of reliable end-use statistics for electric power - Such statistics is fundamental for identification of the changes in consumption patterns for each customer class, or the impacts of energy efficiency and demand-side management programs on the overall system load shape. Similarly, the absence of this statistic impairs the identification of economically proven technologies with

[4] More precisely, electric power intensity of each sector of the economy.

enhanced efficiency characteristics. The importance of availability of reliable end-use statistics can not be overestimate. The last study of the end use characteristics of electricity consumption was conducted by Resource Management Associates of Madison, Wisconsin, in 1998 and has not been renewed since that time.

- Inaccuracy of electricity consumption statistics at the low voltage levels - Any attempts to implement a bottom-up approach to the forecasting of energy demand is impractical due to inaccuracy of electricity consumption statistics at low voltage levels and lack of end-use data mentioned above.
- Absence of performed load study for different customer groups - This type of studies are needed and are important for forecasting, detecting changes in consumption patterns by sector, and tariff setting purposes.

Due to aforementioned lack of basic information, and new factors since the development of the 2002 LCGP, a scenario based approach was used to forecast the electricity demand for the development of the 2005 LCGP. This methodology was used to take into account the new environment in Armenia's electric power sector.

Three scenarios (High, Base Case, and Low) were considered for the 2005 LCGP, which differ by the rate of growth in energy consumption and associated system peak load.

High Growth Scenario is characterized by higher development of industries, due to which annual load factor rises from current 50.0% to 55.1%.

In the Reference Case it is assumed that the main driving factors would be the growth in residential and commercial consumption, while industrial sector would also increase consumption, but not as substantially as the High Growth Scenario. For this reason, the average annual load factor would also increase, but at a lower rate than the High Growth Scenario. Hence, the average annual load factor would reach 52.8%.

The Low Growth scenario is based on the presumption that no substantial changes would occur in the structure of electric power consumption, and the load factor would remain at the same level as it is now – around 50.0%. The load factor assumptions are consistent with high and low load factors shown in Table D.4 excluding 2002 data, which was considered an anomaly due abnormal weather conditions.

The High Growth Scenario projects a 4% growth in generation and 3.4% in peak load. The Reference Growth Scenario forecast a 3.1% growth in generation and 2.7% in peak load, while the Low Growth Scenario assumes that the generation and peak load will increase by 1.9% per annum.

Table D.4. Summary of Demand Scenarios (2005-2025) Analyzed in LCGP 2005

	Base Year 2005	Low Growth Scenario 2025	Reference Growth Scenario 2025	High Growth Scenario 2025
Total Domestic Consumption (GWh)	4,150	6,540	8,048	9,862
Gross Generation for Domestic Needs (GWh)	5,629	8,306	10,170	12,398
Gross Peak Demand (MW)	1,293	1,902	2,198	2,569
Average Annual Load Factor (%)	49.7%	49.9%	52.8%	55.1%
Average Annual Growth Rate of Consumption	na	2.4%	3.4%	4.4%
Average Annual Growth Rate of Generation	na	2.0%	3.0%	4.0%
Average Annual Growth Rate of Peak Demand (%)	na	1.9%	2.6%	3.4%

Accelerated growth rate is assumed for all scenarios during the first half of forecast period. The average annual growth of generation during 2005-2015 is projected to be 5.9%, 4.4% and 3.4% for High, Reference, and Low Case scenarios respectively, as compared to 3.0%, 1.9% and 1.2% during the 2016-2025 timeframe for the three scenarios respectively.

Detailed information regarding the dynamics of consumption development in each sector is presented in table D.5 and forecasts of generation and peak load are presented in table D.6.

Table D.5. Development of Electric Power Consumption by Sector of Economy

Low Growth Scenario

Total sales of electric energy (mln kWhs)											
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential	1523	1600	1664	1713	1765	1809	1845	1873	1901	1920	1939
Budget Organizations	204	210	214	216	218	221	223	224	225	226	227
Industry	946	1022	1083	1116	1138	1155	1173	1190	1211	1231	1255
Irrigation	227	227	226	225	224	223	222	221	219	219	219
Drinking Water	185	189	195	203	213	225	243	265	289	315	341
Transport and Communications	110	110	110	110	110	110	111	111	112	112	113
Other customers	954	1030	1108	1185	1268	1357	1438	1524	1616	1664	1698
Total Domestic consumption	***4150***	***4388***	***4599***	***4768***	***4936***	***5100***	***5255***	***5409***	***5573***	***5689***	***5791***

Low Growth Scenario

Total sales of electric energy (mln kWhs)											Average Growth Rate
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Residential	1959	1976	1994	2010	2026	2040	2054	2067	2079	2090	**1.6%**
Budget Organizations	228	228	228	228	228	229	229	229	229	230	**0.6%**
Industry	1278	1304	1330	1357	1384	1409	1434	1458	1483	1508	**2.4%**
Irrigation	219	219	219	219	219	219	219	219	219	219	**-0.2%**
Drinking Water	364	386	409	434	458	483	510	538	567	595	**6.0%**
Transport and Communications	113	113	113	113	113	113	113	113	113	113	**0.1%**
Other customers	1715	1732	1749	1758	1765	1770	1774	1777	1781	1784	**3.2%**
Total Domestic consumption	***5876***	***5958***	***6043***	***6119***	***6193***	***6263***	***6333***	***6401***	***6472***	***6540***	**2.3%**

Table D.5 (continued). Development of Electric Power Consumption by Sector of Economy

Reference Growth Scenario

Total sales of electric energy (mln kWhs)											
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Residential	1523	1615	1696	1780	1852	1926	2003	2083	2145	2210	2254
Budget Organizations	204	209	214	219	226	233	240	247	254	260	265
Industry	946	965	1004	1064	1128	1196	1256	1306	1358	1412	1455
Irrigation	227	227	226	225	224	223	222	221	219	219	219
Drinking Water	185	189	193	210	231	254	280	308	332	346	356
Transport and Communications	110	110	110	110	110	111	111	112	112	113	114
Other customers	954	1126	1306	1489	1608	1720	1823	1896	1934	1973	2012
Total Domestic Consumption	***4150***	***4441***	***4749***	***5098***	***5379***	***5662***	***5934***	***6172***	***6356***	***6532***	***6675***

Total sales of electric energy (mln kWhs)											**Average Growth Rate**
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	
Residential	2294	2333	2373	2413	2454	2494	2534	2574	2615	2654	**2.8%**
Budget Organizations	270	275	281	284	287	289	292	295	298	301	**2.0%**
Industry	1484	1513	1559	1606	1638	1670	1704	1738	1773	1808	**3.3%**
Irrigation	219	219	219	219	219	219	219	219	219	219	**-0.2%**
Drinking Water	367	378	385	393	401	409	413	417	421	425	**4.2%**
Transport and Communications	114	114	114	114	114	114	114	114	114	114	**0.1%**
Other customers	2053	2094	2136	2178	2222	2266	2312	2381	2452	2526	**5.0%**
Total Domestic Consumption	***6801***	***6927***	***7067***	***7207***	***7334***	***7462***	***7587***	***7738***	***7893***	***8048***	**3.4%**

Table D.5 (continued). Development of Electric Power Consumption by Sector of Economy

High Growth Scenario

Total sales of electric energy (mln kWhs)											
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Residential	1523	1604	1685	1766	1847	1928	2009	2089	2170	2251	2332
Budget Organizations	204	214	225	234	243	250	258	264	270	275	280
Industry	946	1069	1198	1330	1449	1551	1644	1742	1829	1921	2017
Irrigation	227	227	226	225	224	223	222	221	219	219	219
Drinking Water	185	193	199	210	227	248	273	303	333	363	392
Transport and Communications	110	110	110	110	110	110	111	111	112	112	113
Other customers	954	1097	1229	1352	1446	1547	1640	1739	1826	1917	1994
Total Domestic Consumption	***4150***	***4515***	***4871***	***5226***	***5546***	***5857***	***6155***	***6469***	***6759***	***7058***	***7347***

High Growth Scenario

Total sales of electric energy (mln kWhs)											**Average Growth Rate**
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	
Residential	2399	2494	2575	2656	2736	2817	2898	2979	3060	3141	**3.7%**
Budget Organizations	289	298	306	307	307	307	308	308	308	309	**2.1%**
Industry	2098	2161	2225	2292	2338	2385	2432	2481	2531	2581	**5.1%**
Irrigation	219	219	219	219	219	219	219	219	219	219	**-0.2%**
Drinking Water	423	453	498	543	586	633	677	718	754	792	**7.5%**
Transport and Communications	113	113	113	113	113	113	113	113	113	113	**0.1%**
Other customers	2065	2136	2208	2279	2350	2422	2493	2565	2636	2707	**5.4%**
Total Domestic Consumption	***7606***	***7873***	***8145***	***8409***	***8650***	***8897***	***9141***	***9383***	***9621***	***9862***	**4.4%**

Table D.6. Forecasts of Generation and Peak Load

Low Growth Scenario

		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Domestic consumption	GWh	4150	4388	4599	4768	4936	5100	5255	5409	5573	5689	5791
Gross Generation	GWh	5629	5841	6012	6124	6331	6533	6724	6913	7115	7258	7385
Peak Loads	MW	1293	1346	1389	1415	1465	1514	1559	1604	1652	1684	1711
Load Factor	%	49.7%	49.5%	49.4%	49.4%	49.3%	49.3%	49.2%	49.2%	49.2%	49.2%	49.3%

Low Growth Scenario

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average Growth Rate
Total Domestic consumption	GWh	5876	5958	6043	6119	6193	6263	6333	6401	6472	6540	2.379%
Gross Generation	GWh	7488	7590	7694	7788	7879	7965	8051	8136	8223	8306	1.972%
Peak Loads	MW	1733	1753	1774	1793	1810	1826	1842	1857	1873	1902	1.927%
Load Factor	%	49.3%	49.4%	49.5%	49.6%	49.7%	49.8%	49.9%	50.0%	50.1%	49.9%	

Table D.6 (Continued). Forecasts of Generation and Peak Load

Reference Scenario

		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Domestic consumption	GWh	4150	4441	4749	5098	5379	5662	5934	6172	6356	6532	6675
Gross Generation	GWh	5629	5909	6199	6531	6877	7227	7562	7855	8082	8299	8475
Peak Loads	MW	1293	1359	1428	1507	1587	1666	1741	1805	1850	1892	1923
Load Factor	%	49.7%	49.6%	49.6%	49.5%	49.5%	49.5%	49.6%	49.7%	49.9%	50.1%	50.3%

Reference Scenario

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average Growth Rate
Total Domestic consumption	GWh	6801	6927	7067	7207	7334	7462	7587	7738	7893	8048	3.396%
Gross Generation	GWh	8630	8786	8958	9131	9289	9446	9601	9787	9978	10170	2.960%
Peak Loads	MW	1949	1974	2003	2031	2055	2079	2102	2131	2162	2198	2.634%
Load Factor	%	50.6%	50.8%	51.1%	51.3%	51.6%	51.9%	52.1%	52.4%	52.7%	52.8%	

Table D.6 (Continued). Forecasts of Generation and Peak Load

High Growth Scenario

		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Total Domestic consumption	GWh	4150	4515	4871	5226	5546	5857	6155	6469	6759	7058	7347
Gross Generation	GWh	5629	6002	6352	6688	7082	7465	7833	8219	8576	8945	9301
Peak Loads	MW	1293	1379	1458	1532	1618	1699	1775	1854	1925	1997	2064
Load Factor	%	49.7%	49.7%	49.7%	49.8%	50.0%	50.1%	50.4%	50.6%	50.9%	51.1%	51.4%

High Growth Scenario

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average Growth Rate
Total Domestic consumption	GWh	7606	7873	8145	8409	8650	8897	9141	9383	9621	9862	4.401%
Gross Generation	GWh	9620	9948	10282	10608	10906	11209	11510	11808	12101	12398	3.935%
Peak Loads	MW	2121	2179	2238	2293	2341	2390	2437	2482	2525	2569	3.398%
Load Factor	%	51.8%	52.1%	52.5%	52.8%	53.2%	53.5%	53.9%	54.3%	54.7%	55.1%	

5. COMPARISON WITH FORECASTS DEVELOPED BY OTHER ORGANIZATIONS

A comprehensive review of electric power demand forecasts, developed by various organizations, was presented in the 2002 LCGP. Since that time there was only one study carried out by the Energy Strategy Center (ESC) of the Ministry of Energy for the Energy and Nuclear Power Planning Study for Armenia. The study was developed under the auspices of International Atomic Energy Agency.

Although, the report was published in July 2004, it used 1999 data as a base year and the study covered the period of 1999-2020. Energy Strategy Center used MAED model, developed by IAEA, to produce the projections for the study. By 2004, the data used as a base year data for the model projections have become utterly obsolete and no longer reflected the current situation. As a result, the projections of ESC substantially overestimated future demand for energy while predicted peak loads close to the actual loads. This projection was caused by using unrealistically high annual load factors in the model projections. The graphs D.8 and D.9 present LCGP 2005 forecasts along with the ESC projections. To reflect the current situation, the energy and load factor for the ESC base year was changed to be the same as LCGP 2005, while the projected growth rates of ESC projections were preserved. The graphs also show the result of the adjusted ESC forecast.

Figure D.8. LCGP 2005 and ESC Gross Generation Forecast

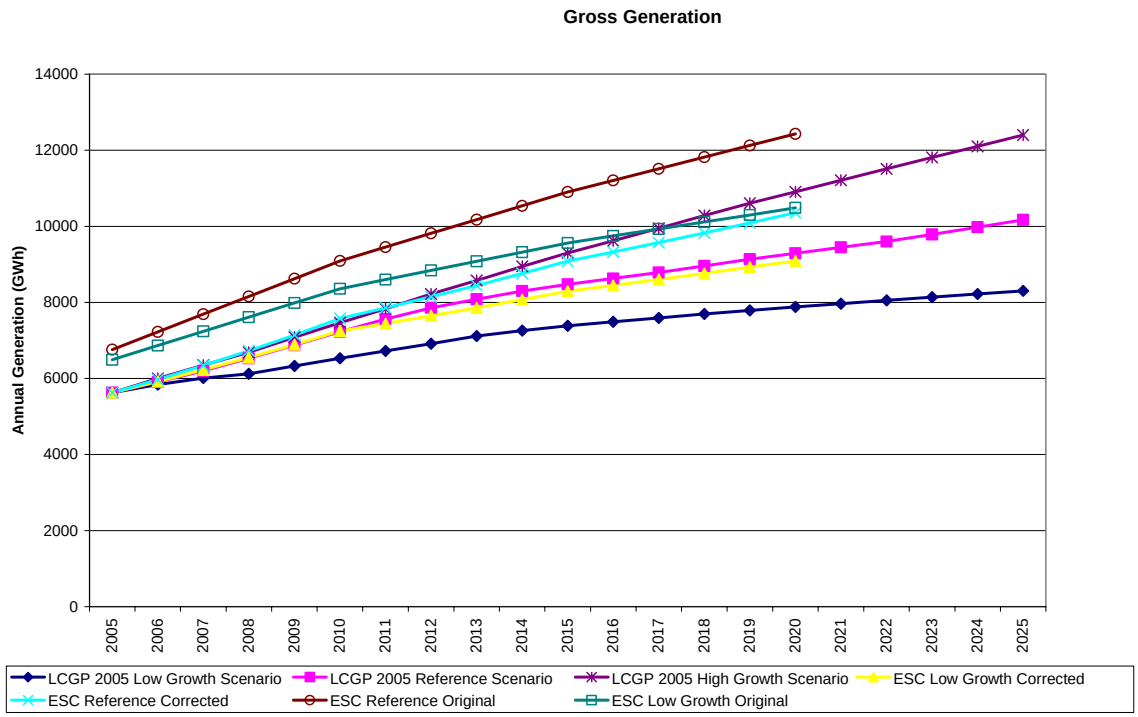
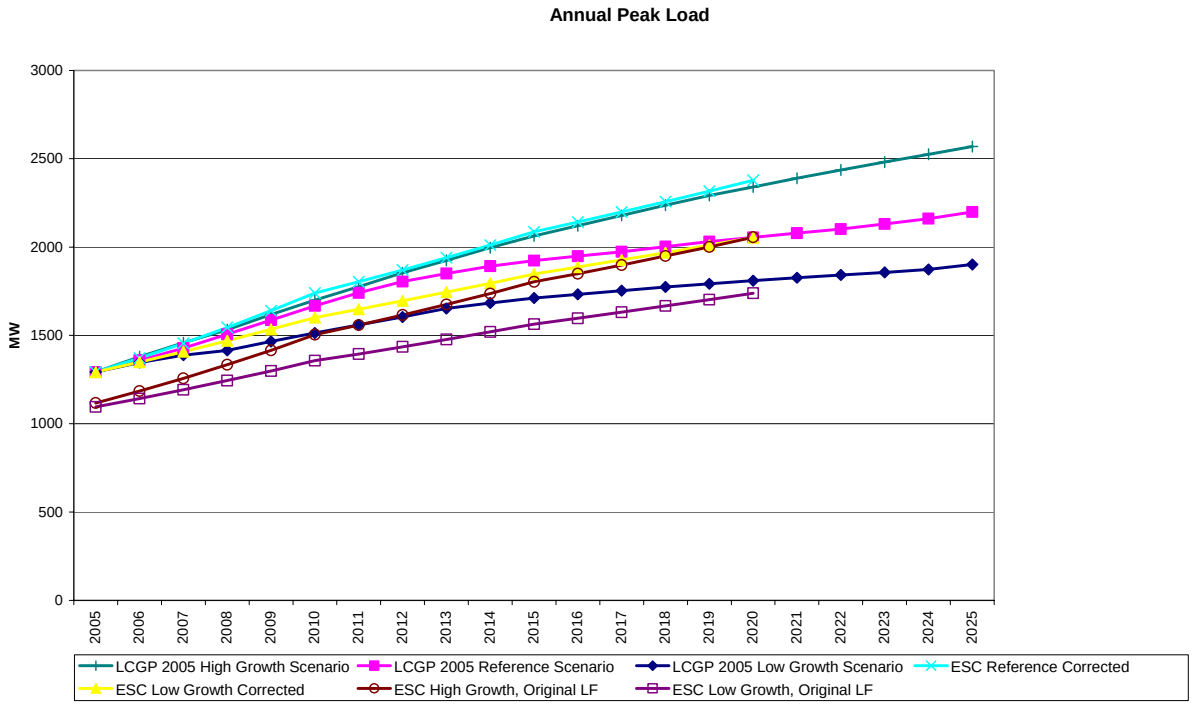
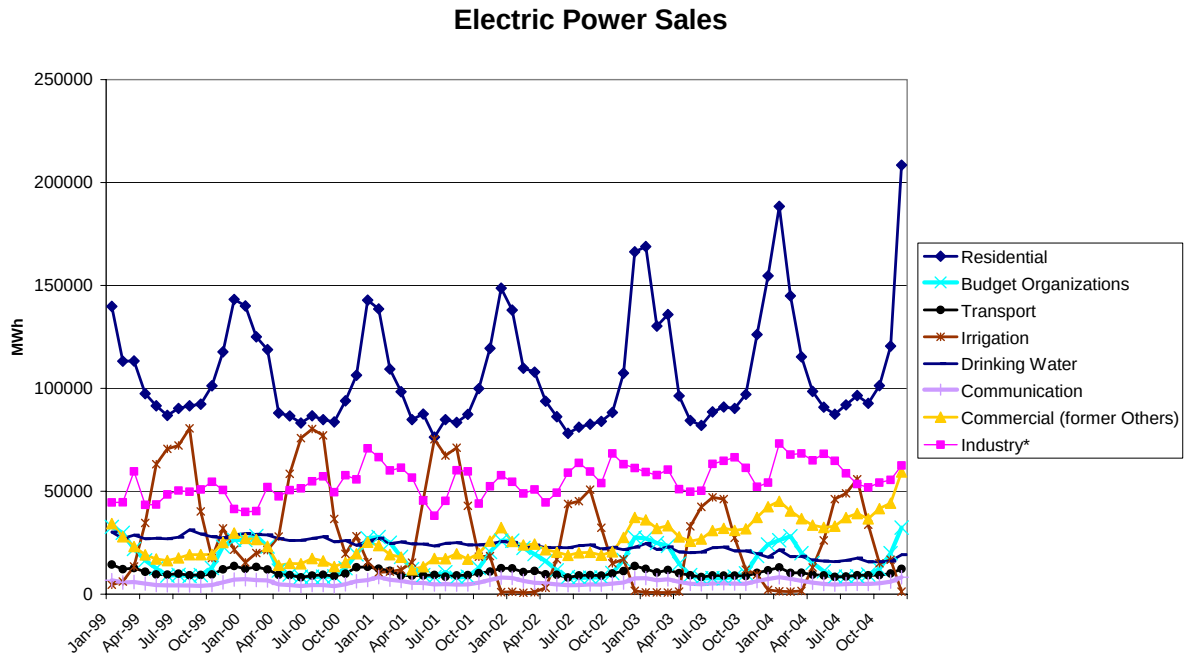


Figure D.9. LCGP 2005 and ESC Peak Load Forecast



ANNEX A: CONSUMPTION OF INDUSTRIAL CONSUMERS WITHOUT CONSTRUCTION ENTERPRISES, CEMENT FACTORIES, BAKERIES AND ENERGY SECTOR ENTERPRISES

Figure A.1. Actual Monthly Sales of Electric Power

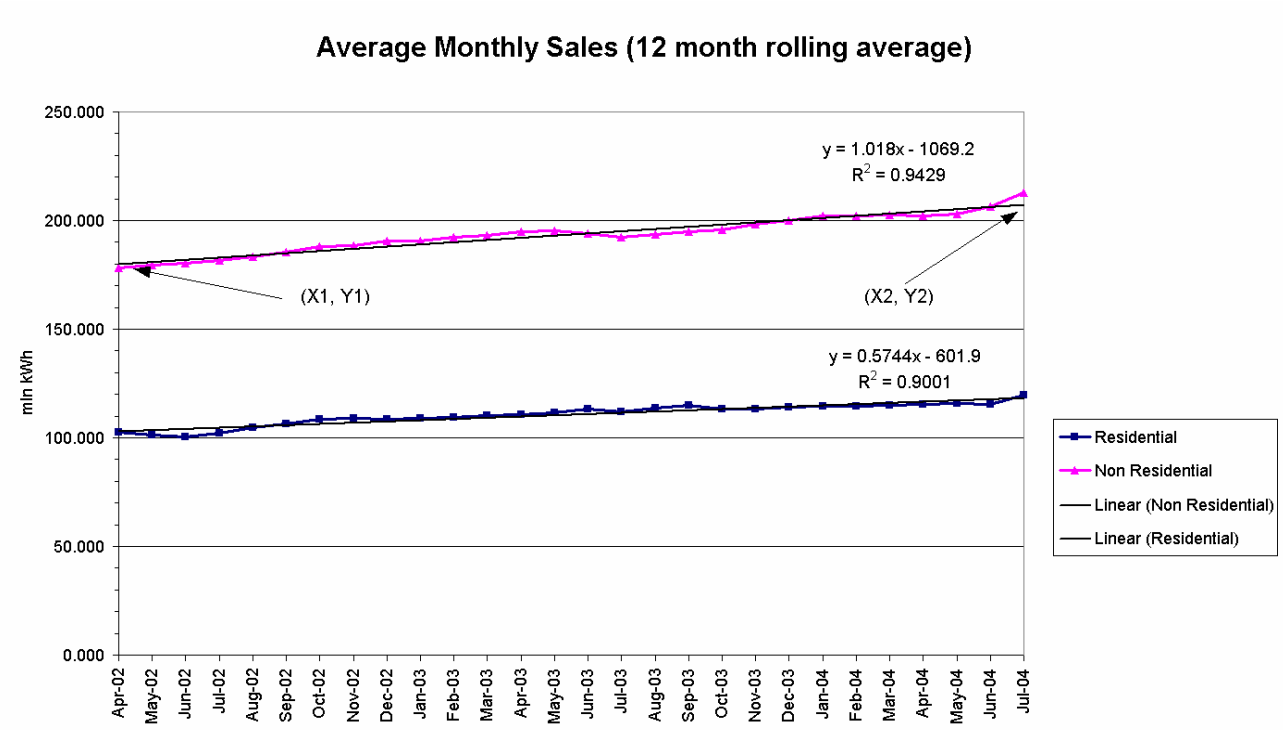


The group indicated as "Industry*" does not include sales to Cement Factories, Construction Enterprises, Bakeries and Energy Sector itself to show the industry's electricity consumption, without these branches. These branches of industry were removed to show that the growth in other branches of industry was rather moderate as compared to the growth exhibited by residential and commercial sectors.

ANNEX B: CALCULATION OF GROWTH RATES FOR RECENT TRENDS IN CONSUMPTION

Calculation of long-term trends and growth rate in consumption is described below. Figure B.1 presents the same data as Figure D.7 along with linear equations automatically produced by Excel for residential and non-residential consumption to represent long- term trends.

Figure B.1. Residential and Non-Residential Consumption during April 2002- July 2004



As the graph shows, the linear trend for non-residential consumption starts at about 180 million kWh in April 2002 and ends up at 206 million kWh in July 2004.

The equation for the trend line is Y=1,018X-1069.2. Thus, the calculation of abscissa X for these values produces 1.227281 and 1.253082. Similar calculations result in 1226.230 and 1256.338 for the trend in residential consumption. Results of calculations are presented in table B.1.

Table B.1. Coordinates of points (X1, Y1) of linear trends for residential and non-residential consumption

	Linear Trend for Residential Consumption	Linear Trend for Non-Residential Consumption
X1	1226.230849	1.227281
Y1	102.447	180.172
X2	1256.338788	1.253082
Y2	119.741	206.438

The considered period spans 28 months between April 2002 and July 2004. The value of a linear trend can be calculated for each month within this period. The results of these calculations are presented in tables B.2 and B.3. Also, these tables show average growth rates calculated on annual bases for the obtained trends. The linear form of a trend is necessary to determine the decline in growth rates for the period, since this is a feature of a linear equation.

As the tables illustrate, the annual growth of a trend for residential consumption is 6.9%, while for the non-residential consumption it is around 6.05% per year. For a long–term projection we assume lower growth rates for several reasons. As discussed previously, it is unclear what portion of the recent growth in the residential sector was caused by improvement in overall economic situation and what was caused due to reduction in commercial losses.

The growth was primarily associated with the growth in residential sector, commercial sector and those branches of industry that are related to construction and commercial activities. Much of this growth was supported by increase in private transfers of funds from abroad, which can hardly be considered as a sustainable factor from a long-term prospective.

The growth rate of total effective demand, calculated for 2003 and 2004 (Figure D.4), was 5.32% and 2.04%.

Table B.2. Residential Sector Monthly Consumption and Linear Trends

Annual Growth Rate of Linear Trend	Month	Actual Consumption	Abscissa X	Value of Linear Trend
7.50%	Apr-02	102.447	1226.230	102.447
7.46%	May-02	101.482	1227.345	103.087
7.41%	Jun-02	100.474	1228.461	103.728
7.36%	Jul-02	101.945	1229.576	104.368
7.32%	Aug-02	104.522	1230.691	105.009
7.28%	Sep-02	106.223	1231.806	105.649
7.23%	Oct-02	108.560	1232.921	106.290
7.19%	Nov-02	108.776	1234.036	106.930
7.15%	Dec-02	108.615	1235.151	107.571
7.10%	Jan-03	108.935	1236.266	108.211
7.06%	Feb-03	109.557	1237.381	108.852
7.02%	Mar-03	110.254	1238.497	109.492
6.98%	Apr-03	110.782	1239.612	110.133
6.94%	May-03	111.517	1240.727	110.773
6.90%	Jun-03	113.085	1241.842	111.414
6.86%	Jul-03	112.115	1242.957	112.054
6.82%	Aug-03	113.740	1244.072	112.695
6.78%	Sep-03	114.963	1245.187	113.335
6.74%	Oct-03	113.249	1246.302	113.976
6.71%	Nov-03	113.434	1247.417	114.616
6.67%	Dec-03	113.973	1248.533	115.257
6.63%	Jan-04	114.426	1249.648	115.897
6.60%	Feb-04	114.706	1250.763	116.538
6.56%	Mar-04	115.167	1251.878	117.178
6.52%	Apr-04	115.376	1252.993	117.819
6.49%	May-04	115.728	1254.108	118.459
6.45%	Jun-04	115.261	1255.223	119.100
6.42%	Jul-04	119.741	1256.338	119.741

Table B.3. Non-Residential Monthly Consumption and Linear Trends

Annual Growth Rate of a Linear Trend	Month	Actual Consumption	Abscissa X	Value of Linear Trend
6.48%	Apr-02	178.234	1.227	180.172
6.44%	May-02	179.379	1.228	181.145
6.41%	Jun-02	180.172	1.229	182.118
6.38%	Jul-02	181.512	1.230	183.090
6.34%	Aug-02	183.187	1.231	184.063
6.31%	Sep-02	185.530	1.232	185.036
6.28%	Oct-02	187.911	1.233	186.009
6.24%	Nov-02	188.535	1.234	186.982
6.21%	Dec-02	190.776	1.235	187.954
6.18%	Jan-03	190.385	1.236	188.927
6.15%	Feb-03	192.287	1.237	189.900
6.12%	Mar-03	193.256	1.238	190.873
6.08%	Apr-03	194.730	1.239	191.846
6.05%	May-03	195.091	1.240	192.818
6.02%	Jun-03	194.061	1.241	193.791
5.99%	Jul-03	192.405	1.242	194.764
5.96%	Aug-03	193.769	1.243	195.737
5.93%	Sep-03	195.039	1.244	196.709
5.91%	Oct-03	195.637	1.244	197.682
5.88%	Nov-03	198.395	1.245	198.655
5.85%	Dec-03	199.952	1.246	199.628
5.82%	Jan-04	201.952	1.247	200.601
5.79%	Feb-04	202.032	1.248	201.573
5.76%	Mar-04	202.426	1.249	202.546
5.74%	Apr-04	201.965	1.250	203.519
5.71%	May-04	203.112	1.251	204.492
5.68%	Jun-04	206.437	1.252	205.465
5.65%	Jul-04	212.900	1.253	206.437

APPENDIX E:

Fuel Price Forecast Update

Armenian Power Sector 2006 Least Cost Generation Plan

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Annex E - A: List of Acronyms used in Table E.2 **A-1**

1. INTRODUCTION

Armenia has been privy to discounted gas prices from Russia since the 90's. However, Armenia has been informed by its supplier that its gas prices will increase in 2006.

Armenia is primarily dependent on nuclear fuel and natural gas for base load power generation and on natural gas for peak load. Other fossil fuels are not readily available and transportation and environmental related costs makes them economically undesirable. Renewable sources such as wind and hydro are available but can not provide base load electric power on demand. Therefore, the LCGP 2006 only considers nuclear fuel and natural gas price forecasts. Nuclear fuel prices and costs were discussed in Appendix A; this Appendix presents the forecasts for natural gas prices.

2. PRECONDITIONS OF FORECASTING

The preconditions for forecasting fuel prices for the LCGP 2005 have substantially changed since 2002, when the last LCGP was prepared. In this regard the price of natural gas for Armenia has become one of the major, if not the most significant, source of uncertainty. Natural gas price is significantly impacted by the worldwide crude oil market price. To illustrate the impact of crude oil prices on natural gas prices and the level of uncertainty associated with it, Figure E.1 presents evolution of imported crude oil price in the US over the last 25 years. As the graph shows, measured in 2005 constant dollars, the current effective price is at about two thirds[1] of its peak of February 1981 (first Iran-Iraq war), but since December 2001, oil prices have been steadily on the rise. The growth is mainly attributed to the solid rise of demand in China and India, while seasonal fluctuations and irregularities of overall price pattern were caused by unpredictable events such as wars or supply disruptions.

The recent changes in world crude oil prices caused similar alterations in long-term predictions, reliability and precision in forecasts of natural gas prices. Table E.1 presents information on the accuracy of EIA forecasts of natural gas prices, accumulated over the same period of time. As the table indicates, starting from 1993, all forecasts developed for 2003 tend to underestimate future natural gas price growth. From Figure E.1, it is clear that the period from 1992 through 2001 was a declining period for the oil prices. These declining oil prices caused lower U.S. natural gas price forecasts for 2003 for most of this period. The negative impact of higher than predicted natural gas prices has resulted in cancellation of many natural gas-fired power projects and reduced dispatch for the existing ones.

Because of a high degree of dependency of the electric power sector of Armenia on gas-fired generation and impact of fuel prices on generation technologies choices, it is important to capture the potential impact of crude oil prices on natural gas as fully as possible.

[1] As of September 2005.

Figure E.1. Crude Oil Price Over the Past 25 Years

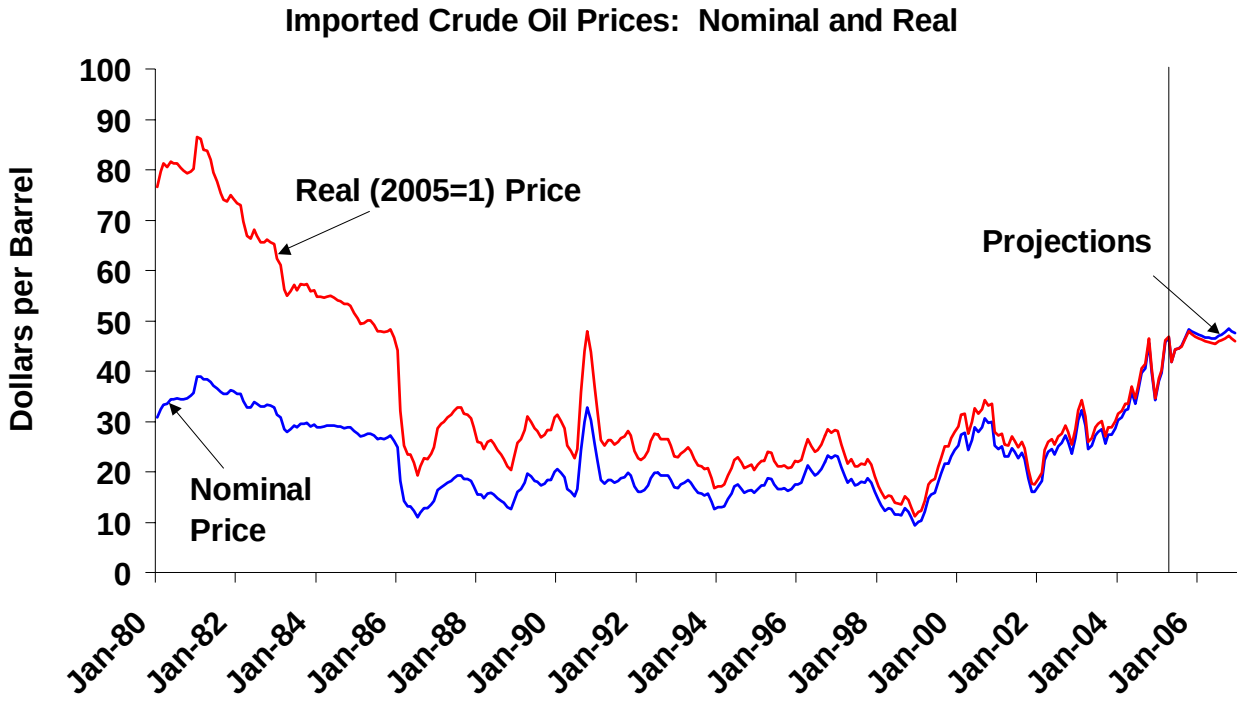


Table E.1. Forecasted and actual wellhead prices of natural gas in the USA.

Table 13. Natural Gas Wellhead Prices, Actual vs. Forecasts
(current dollars per thousand cubic feet)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
AEO 1982	4.32	5.47	6.67	7.51	8.04	8.57													
AEO 1983	2.93	3.11	3.46	3.93	4.56	5.26					12.74								
AEO 1984	2.77	2.90	3.21	3.63	4.13	4.79					9.33								
AEO 1985	2.60	2.61	2.66	2.71	2.94	3.35	3.85	4.46	5.10	5.83	6.67								
AEO 1986		1.73	1.96	2.29	2.54	2.81	3.15	3.73	4.34	5.06	5.90	6.79	7.70	8.62	9.68	10.80			
AEO 1987			1.83	1.95	2.11	2.28	2.49	2.72	3.08	3.51	4.07					7.54			
AEO 1989*				1.62	1.70	1.91	2.13	2.58	3.04	3.48	3.93	4.76	5.23	5.80	6.43	6.98			
AEO 1990					1.78	1.88					2.93					5.36			
AEO 1991						1.77	1.90	2.11	2.30	2.42	2.51	2.60	2.74	2.91	3.29	3.75	4.31	5.07	5.77
AEO 1992							1.69	1.85	2.03	2.15	2.35	2.51	2.74	3.01	3.40	3.81	4.24	4.74	5.25
AEO 1993								1.85	1.94	2.09	2.30	2.44	2.60	2.85	3.12	3.47	3.84	4.31	4.81
AEO 1994									1.98	2.12	2.27	2.41	2.59	2.73	2.85	2.98	3.14	3.35	3.59
AEO 1995										1.89	2.00	1.95	2.06	2.15	2.40	2.57	2.90	3.16	3.56
AEO 1996											1.63	1.74	1.86	1.99	2.10	2.19	2.29	2.38	2.48
AEO 1997												2.03	1.82	1.90	1.99	2.06	2.13	2.21	2.32
AEO 1998													1.63	1.74	2.26	2.31	2.38	2.44	2.52
AEO 1999														2.00	2.15	2.20	2.32	2.43	2.53
AEO 2000															2.15	2.23	2.27	2.32	2.40
AEO 2001																3.39	3.48	2.97	2.74
AEO 2002																	4.03	2.06	2.53
AEO 2003																		2.79	3.26
AEO 2004																			4.97

Actual	**2.51**	**1.94**	**1.67**	**1.69**	**1.69**	**1.71**	**1.64**	**1.74**	**2.04**	**1.85**	**1.55**	**2.17**	**2.32**	**1.96**	**2.19**	**3.68**	**4.00**	**2.95**	**4.98**
Average Absolute Error (All AEOs)	**0.6**	**1.3**	**1.6**	**1.7**	**1.8**	**1.9**	**0.9**	**1.0**	**1.0**	**1.3**	**3.0**	**1.0**	**1.2**	**1.3**	**1.4**	**1.7**	**1.0**	**0.8**	**1.7**
percent error																			
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**
AEO 1982	**72.0**	**182.1**	**299.6**	**344.6**	**375.6**	**401.0**													
AEO 1983	**16.7**	**60.1**	**107.4**	**132.5**	**169.8**	**207.4**					**721.7**								
AEO 1984	**10.4**	**49.3**	**92.3**	**114.6**	**144.6**	**180.1**					**501.7**								
AEO 1985	**3.6**	**34.4**	**59.0**	**60.2**	**74.2**	**95.9**	**135.0**	**156.3**	**150.1**	**215.4**	**330.3**								
AEO 1986		**-10.8**	**17.1**	**35.4**	**50.5**	**64.4**	**91.9**	**114.2**	**112.9**	**173.4**	**280.3**	**213.0**	**231.9**	**339.9**	**341.8**	**193.4**			
AEO 1987			**9.6**	**15.2**	**24.6**	**33.5**	**51.5**	**56.6**	**51.0**	**89.7**	**162.9**					**105.0**			
AEO 1989*				**-4.1**	**0.6**	**11.4**	**29.9**	**48.1**	**49.1**	**88.1**	**153.5**	**119.5**	**125.3**	**195.8**	**193.7**	**89.7**			
AEO 1990					**5.3**	**10.2**					**89.1**					**45.8**			
AEO 1991						**3.5**	**15.8**	**21.3**	**12.8**	**30.6**	**61.7**	**19.9**	**17.9**	**48.5**	**50.2**	**1.8**	**7.8**	**71.9**	**15.9**
AEO 1992							**2.8**	**6.2**	**-0.4**	**16.1**	**51.6**	**15.7**	**18.2**	**53.7**	**55.1**	**3.5**	**5.9**	**60.5**	**5.5**
AEO 1993								**6.1**	**-5.1**	**13.0**	**48.5**	**12.4**	**12.0**	**45.2**	**42.7**	**-5.8**	**-3.9**	**45.9**	**-3.4**
AEO 1994									**-2.8**	**14.9**	**46.2**	**11.0**	**11.5**	**39.2**	**30.4**	**-19.0**	**-21.5**	**13.4**	**-27.9**
AEO 1995										**2.3**	**28.9**	**-10.0**	**-11.0**	**9.8**	**9.6**	**-30.2**	**-27.6**	**7.1**	**-28.6**
AEO 1996											**5.2**	**-19.8**	**-19.7**	**1.6**	**-3.9**	**-40.4**	**-42.8**	**-19.4**	**-50.3**
AEO 1997												**-6.3**	**-21.4**	**-2.8**	**-9.2**	**-43.9**	**-46.6**	**-25.0**	**-53.5**
AEO 1998													**-29.6**	**-11.0**	**3.0**	**-37.2**	**-40.5**	**-17.1**	**-49.5**
AEO 1999														**2.1**	**-1.9**	**-40.1**	**-42.1**	**-17.8**	**-49.2**
AEO 2000															**-2.0**	**-39.3**	**-43.3**	**-21.4**	**-51.9**
AEO 2001																**-7.8**	**-12.9**	**0.8**	**-45.0**
AEO 2002																	**0.6**	**-30.1**	**-49.1**
AEO 2003																		**-5.6**	**-34.6**
AEO 2004																			**-0.2**
Average Absolute Percent Error (All AEOs)	**25.7**	**67.3**	**97.5**	**100.9**	**105.7**	**111.9**	**54.5**	**58.4**	**48.0**	**71.5**	**190.9**	**47.5**	**49.8**	**68.2**	**62.0**	**46.9**	**24.6**	**25.8**	**33.2**

*** There is no report titled *Annual Energy Outlook 1988* due to a change in the naming convention of the *AEO* s.**

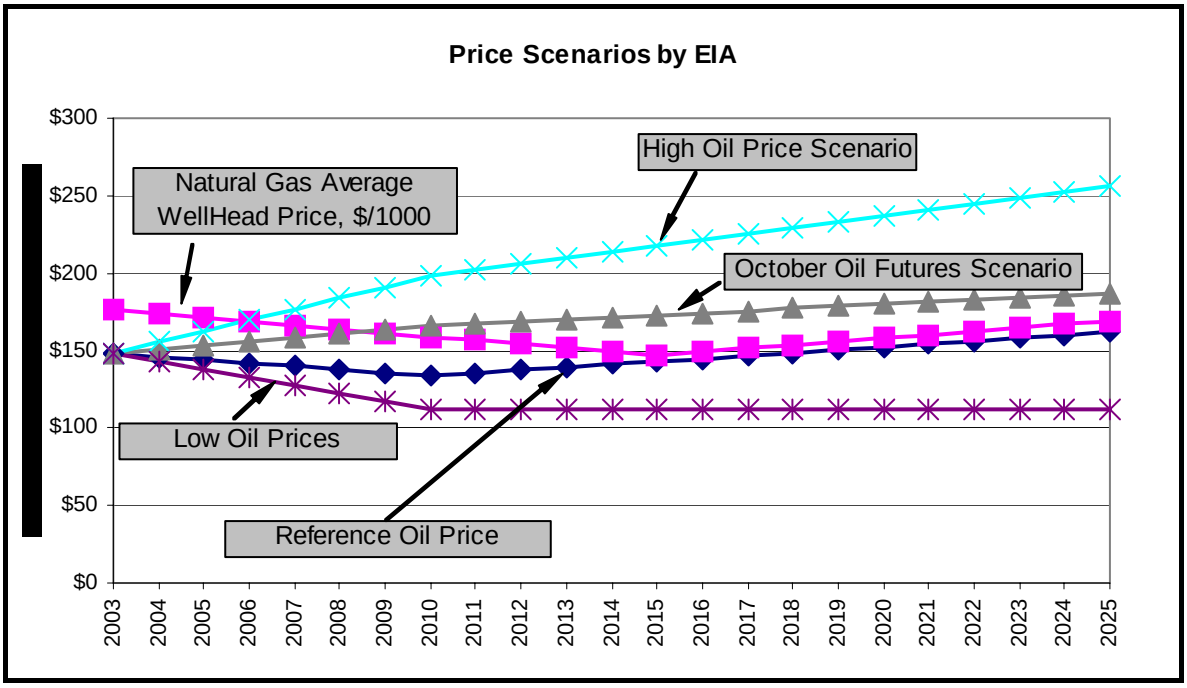
Sources: **Forecasts: *Annual Energy Outlook* , Mid-Price or Reference Case Projections, Various Editions**

Historical Data: Energy Information Administration, *Annual Energy Review 2003* , DOE/EIA-0384(2003) (Washington, DC, September 2004) , Table 6.7

Source: EIA, Energy Information Administration, Annual Energy Review 2003, DOE/EIA-0384(2003) (Washington, DC, September 2004), Table 6.7

The natural gas price scenarios developed for the LCP 2002 were primarily based on the assumptions regarding operational costs of the gas industry. For the 2005 forecast, an important provision has been adopted that contrary to the situation three years ago, the future development of gas prices would be driven not only by costs incurred by the gas industry, but also by the value of gas. This supposition is concurrent with the opinions of internationally recognized experts in this subject [e.g. the US Energy Information Administration (EIA), EU International Energy Agency (IEA), and Centre for Energy Research of the Netherlands]. For example, in its reference crude oil price forecast of 2005, the EIA draws a conclusion that wellhead gas prices in the US would develop to such level that the natural gas price calculated on the basis of energy parity would be even higher than that for crude oil prices, which would signal to gas consumers to switch from natural gas to other sources of energy (Figure E.2) to correct market imbalances. The natural gas price was forecasted in relation to the reference oil price scenario.

Figure E.2. Energy Information Administration Crude Oil and Natural Gas Price Scenarios



Although this conclusion may hold true for the U.S. market, it should not be universally taken for granted because a world natural gas market does not exist with respect to pipe supplied gas. This market is substantially more localized in its nature and formation of prices is to a much higher extent driven by availability and costs of pipe transportation routs. For LCGP 2005, in the approach to forecasting the natural gas price for Armenia, the most realistic internationally recognized forecasts of world crude oil prices were chosen. Furthermore, several important indictors were developed to relate these prices to natural gas prices and take into account peculiarities of the Armenia's regional natural gas market.

The projections of future world crude oil prices developed by Energy Information Administration are taken as a basis for natural gas price forecasting for the LCGP 2005. EIA re-evaluated its forecasts substantially between April 2004, when the *International Energy Outlook 2004* (AEO2004) annual report was published, and February 2005, when *Annual Energy Outlook 2005* (AEO2005) was issued. Corrections to the previous forecasts, which were made in the latest edition of the report, are shown in Table E.2. The 2004 and 2005 projections are designated as AEO2004 and AEO2005 respectively. The acronyms used in Table E.2 are defined in Annex E-A.

Table E.2. Comparison of World Oil Price Forecasts by Different Organizations

Table 33. Forecasts of world oil prices, 2010-2025 (2003 dollars per barrel)

Forecast	2010	2015	2020	2025
AEO2004 (reference case)	24.53	25.44	26.41	27.40
AEO2005				
Reference	25.00	26.75	28.50	30.31
High A world oil price	33.93	34.24	36.74	39.24
High B world oil price	37.00	40.67	44.33	48.00
October oil futures	30.93	32.33	33.67	35.00
Low world oil price	20.99	20.99	20.99	20.99
GII	27.08	25.58	26.66	27.12
IEA (reference scenario)	23.25	25.37	27.48	29.07
IEA (high oil price case)	37.00	37.00	37.00	37.00
Altos	21.92	22.67	23.93	24.60
PEL	25.00	27.00	27.00	29.00
PIRA	34.75	39.15	NA	NA
DB	24.00	24.00	24.00	24.00
EEA	26.58	25.55	24.93	NA
SEER	26.13	28.40	28.25	29.00
EVA	28.93	28.39	30.97	34.77

NA = not available

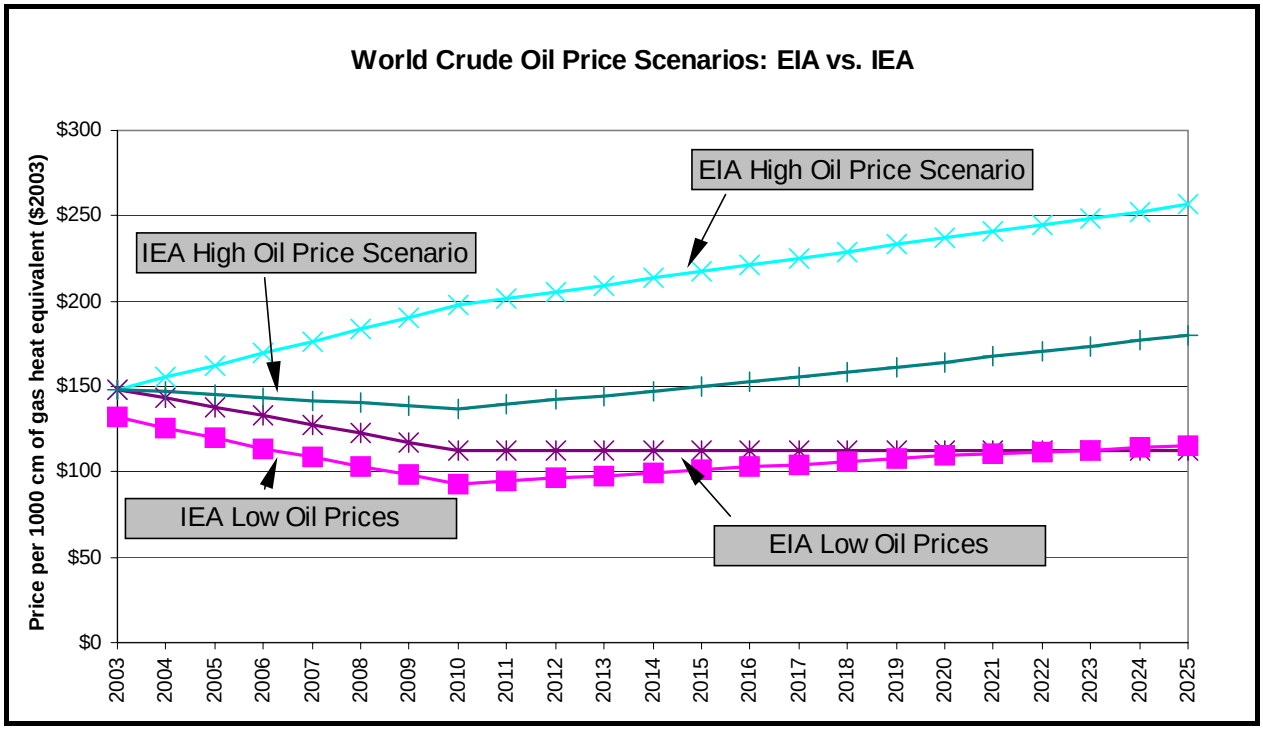
Source: *Annual Energy Outlook 2005.*

As reflected in the table, the EIA has increased its reference case forecast by almost $3 per barrel for 2025. Another important observation is that the difference between International Energy Agency reference scenario and Energy Information Administration reference scenario is insignificant – $29.07 versus $30.31 per barrel in 2025. In other words, as indicated in Table E.2 and Figure E.3 these two organizations' opinions regarding the forecast of the most probable or low oil price concur. However, their views with regard to the high oil prices diverged after EIA updated its forecasts (Figure E.3).

Apart from the increase in the reference scenario price projections, the IEA has developed an additional potential price alternative based on the NYMEX October 2005 Oil Futures prices for crude oil. In 2025 this scenario is lower than the IEA High Price case by mere $2 per barrel. It is worth noting that the International Energy Agency developed its forecasts in 2003, when only one year of a steady price growth period had elapsed after a drop in 2002.

As a basis for further development of natural gas price forecast for Armenia, two scenarios are considered – the AEO 2005 Reference Case and AEO 2005 October Oil Future Case. These two scenarios represent the most probable development of the world crude oil prices and for this reason they have been selected as a basis for forecasting natural gas price for Armenia. As indicated in Table E.2, neither of these cases represents overly pessimistic or optimistic views of the future, though they predict slightly higher than average price growth.

Figure E.3 Updated EIA forecast versus IEA forecast



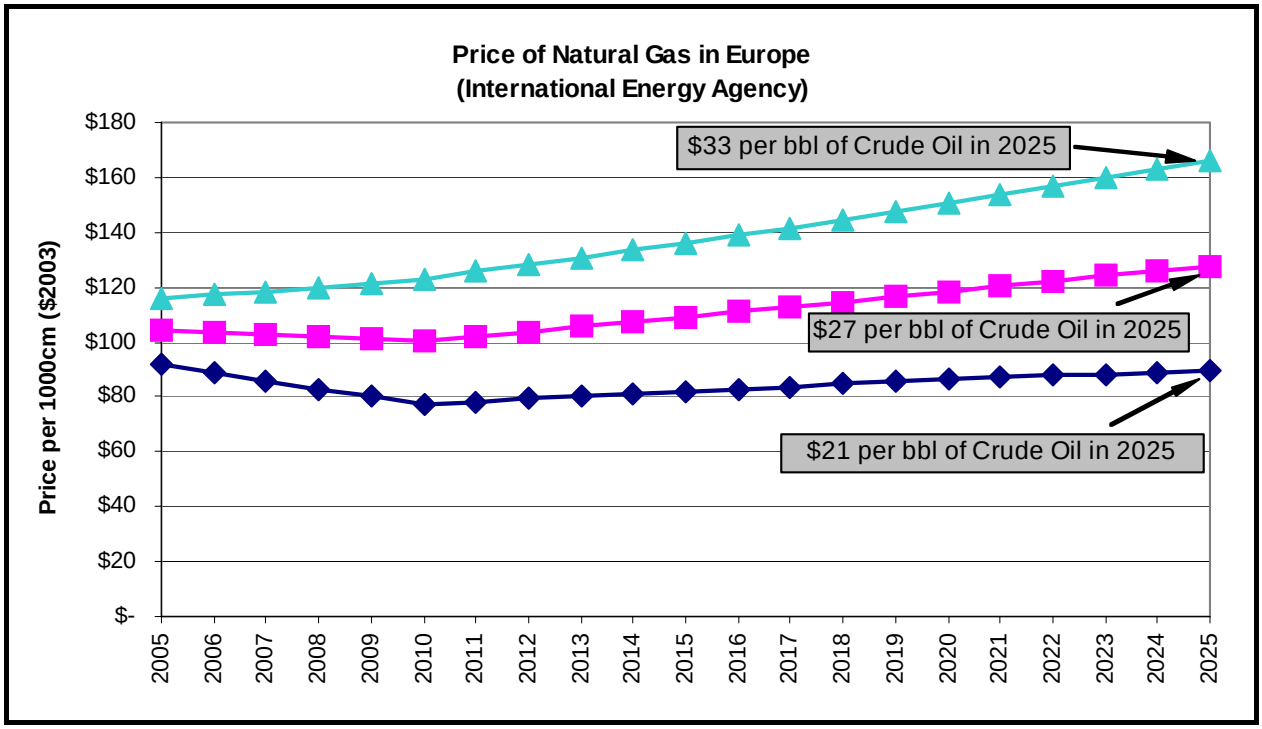
3. RISING VALUE OF NATURAL GAS FOR WESTERN EUROPE

Forecasts of the natural gas price for Europe is well in line with the projections of the EIA's world crude oil prices used as the basis for European projections, which ranges from $128 to $166 (for the reference and high case respectively) per 1000 cubic meters of gas heat equivalent in 2025. They are associated with $27 and $31 per bbl of crude oil as shown in Figure E.4, versus $30.31and $35 per bbl of crude for the reference and October Oil Futures cases indicated in Table E.2.

Another principal factor well illustrated in the IAE forecast, important for the forecasting of the natural gas price in Armenia, is potential changes in a value of natural gas versus crude oil, which can be shown by the variations in relative prices of these primary energy sources when calculated on energy equivalent basis. The relative price of gas to oil projected to change from 0.71 in 2000 to 0.93 and 0.87 in 2025 for the high and reference case respectively (Annex E-D). Therefore, the second important factor that has been included in forecasting natural gas price, for the LCGP 2005, is its rising value.

At present only one gas pipeline supplies natural gas to Armenia from Russia through the territory of Georgia. And since 1994, when Azerbaijan declared boycott on energy supply to Armenia, Russia has been the only source of primary energy for the country. Currently, Iran- Armenia gas pipeline is under construction and is projected to be completed in 2007. According to preliminary agreements between Iran and Armenia, the price of Iranian gas at the border of Armenia would be $80 per 1000 cm versus current $54 for the Russian gas. However, per ArmRosGasprom, the price of gas from Russia is projected to increase to $100 per 1000 cm by the end of this decade. Due to lack of information and uncertainties associated with the Iranian gas imports, further analysis is focused exclusively on projection of the price of natural gas from Russia. However, the potential price for Iranian gas is not expected to be lower than the Russian gas.

Figure E.4. Forecasts of natural gas price for Western Europe



4. NATURAL GAS PRICE AT THE BORDER OF ARMENIA

Two important events occurred in the recent past, which substantially changed the fuel forecast conditions for LCGP. On December 30, 2005, Russia increased the price for natural gas at the border with Armenia, and the US Energy Information Administration published an early release of Annual Energy Outlook 2006 with updated long-term projections of world crude oil price, which captured crude oil price developments of late 2005 - early 2006.

According to the new Russia-Armenia agreement, the price of imported natural gas from Russia in 2006 will equal $110 per thousand. cubic meter (tcm), which is more than 100% higher than the 2005 price of $54 per tcm. This price increase introduces a substantial change in relative economics of different generating options.

For the reference case, the early release of Annual Energy Outlook 2006 foresees profound increase in the world crude oil price in comparison with the projections of the previous year: $46.77[2] per bbl in 2025 versus $35 as projected in the World Annual Outlook 2005, for the October Crude Oil Future Prices scenario.

Following the logic of the previous analysis, the following assumptions were made:

1. In 2025 the natural gas price at the western border of Russia would make up 96% of its value, on an energy equivalent basis, based on the world crude oil price;
2. The price of the natural gas at the border of Armenia would make up 95% of the export natural gas price at the western border of Russia.

During the preparation of the LCGP 2006 Update, it became known that the natural gas price at the border of Armenia would remain unchanged[3] at $110 per tcm through December 31, 2008. This fact became known after the fuel price forecast was updated, which assumed a uniform rate of growth from 2006 through 2025. According to the assumptions made, the border price of gas would be $112.7 and $115.5 per tcm in 2007 and 2008 respectively. The price differentials of $2.7 and $5.5 are below the level of sensitivity of optimal solution and do not change the overall generation strategy.

Furthermore, a very conservative assumption was made regarding the price of natural gas during the 2008- 2025. It is assumed that the price of gas for Armenia would reach 95% of the export gas price at the Western border of Russia and that the rate of growth would be uniform over this period. The latter assumption may substantially underestimate the cost of fuel for thermal power plants. On the other hand, the non-thermal technologies that prove to be economically feasible under this conservative uniform growth scenario, would become even more attractive in case of a sharp gas price increase.

Principal assumptions regarding main driving factors of the natural gas price in LCGP 2005 and LCGP Update 2006 are summarized in Table 1.1.1. Contrary to the LCGP 2005, the 2006 Update is based on a single scenario for natural gas price.

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[2] The EIA projects $47.99 per bbl in 2004 dollars, which translates into $46.77 in 2003 dollars for comparison with previous projections, expressed in 2003 dollars.

[3] The constant gas price through the end of 2008 is one of the conditions of Hrazdan unit #5 transfer to the Russian owner.

Table 1.1.1. Principal Assumptions for Forecasting Natural Gas Price at the Armenian Border

Natural Gas Price Forecast for LCGP 2005		
Scenarios	**Moderate Growth Case**	**High Growth Case**
World Crude Oil Price	Reference Case of EIA: $30.31 per bbl ($161.99 per tcm) in 2025	October Crude Oil Futures Prices Case of EIA: $35 per bbl ($187.05 per tcm) in 2025
Natural Gas price at the Western Border of Russia	86% of its value by energy equivalent by 2025	96% of its value by energy equivalent by 2025
Level of the Border Price for Armenia compared to the price at Western border of Russia	Would grow evenly over the period and reach 100% of forecasted growth by 2025	From current 42% would reach 80% by 2010 and 90% by 2025
Natural Gas Price Forecast for LCGP 2006 Update		
World Crude Oil Price		Reference Case of EIA from AEO2006: $46.77 per bbl ($249.94 per tcm) in 2025
Natural Gas Well Head Price in the USA		$4.52 per tcm in 2015; $5.43 per tcm in 2025;
Natural Gas price at the Western Border of Russia		96% of Gas well Head Price in 2025
Level of the Border Price for Armenia compared to the price at Western border of Russia		95% of Export Gas Price at the western Border of Russia by 2025;
Assumptions concerning growth rates		Gas price at the border of Armenia would grow at a uniform growth rate through 2025

5. NATURAL GAS TARIFF FOR GENERATORS

To derive the price for generators, further assumptions were made concerning the structure of the gas price for large customers in Armenia.

In the previous analysis it was assumed that operating expenses, technical losses and Armrosgasprom's margin would remain constant (expressed in constant dollars) through the projection period. For the renewed forecast two of the mentioned three parameters remained unchanged, namely the value of operating expenses at $8.60 per tcm and the margin at $1.20 per tcm.

Different approach was taken to calculate losses. It was assumed that the cost of losses would be changing in accordance with the changes in gas price at the border, since losses actually represent the cost of gas used in compressors. Therefore, this cost will change parallel with the gas price at the border. Further it was assumed that the cost of technical losses, expressed as a percent of the border gas price, would remain constant.

Based on the data used in earlier analysis, the cost of losses make up 5.61% of the border gas price, of which 3.24% are attributed to transportation and 2.37% to distribution of gas (see the table below). Based on this level of losses and the new gas price at the border, the tariff for large industrial customers should equal $151.17 per tcm. However, in March 2006 Armroasgasprom submitted a tariff increase request to the PSRC, and the Commission set the price for large industrial customers (including power plants) at $146.51 per tcm.

Table 1.1.2. Calculation of Natural Gas Sales Price for LCGP 2006 Update

	Large consumers, annual use>10,000cm	Losses as % of the border price	Tariff for large consumers at new border price	Armrosgasprom Tariff Request for 2006
Price at the border	$54.00		$110.00	
Operating expenses	$8.60		$8.60	
Technical losses:	$3.03	5.61%	$6.17	
Transportation	$1.75	3.24%	$3.56	
Distribution	$1.28	2.37%	$2.61	
Armrosgasprom margin	$1.20		$1.20	
Sales price, w/o VAT	$66.90		$125.97	
VAT	$13.20		$25.19	
Consumer sales price	**$79.10**		**$151.17**	**$146.51**
		Tariff Differential:		**$4.66**

Thus, the differential between our calculations and actual requested rate is equal to $4.66 per tcm. This differential was considered in the updated forecast (results of the calculations performed according to the LCGP-2005 methodology were reduced by this amount).

5. Natural Gas Tariff for Generators

The following Figure and Tables present the forecasts of the natural gas price for thermal power plants used in LCGP 2005 and 2006 Update.

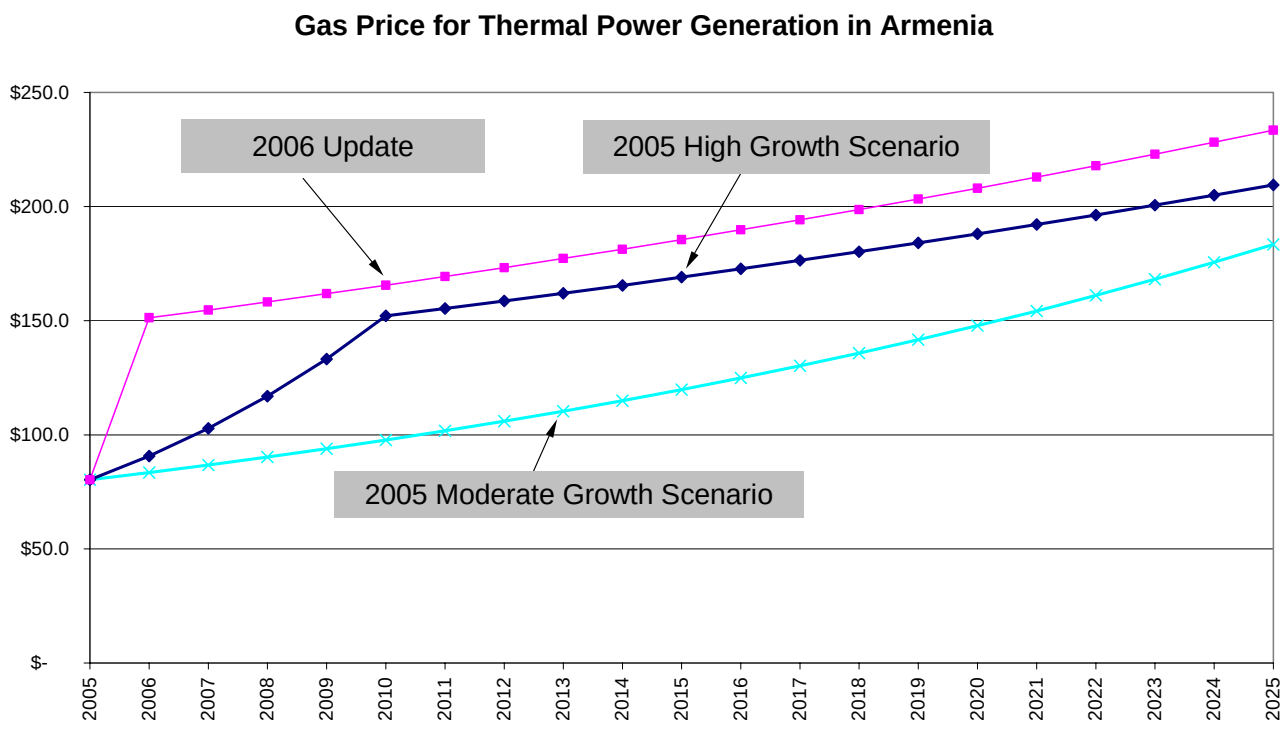

Fig. 1.2.1. Forecasted Price of Natural Gas for Thermal Generation in Armenia.

Table 1.2.1. Forecast of the Delivered Gas Prices to Thermal Plant Sites in Armenia Based on the Forecasted Border Gas Prices

2006 Update

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Price at border	$ 110.0	$ 112.7	$ 115.5	$ 118.4	$ 121.3	$ 124.3	$ 127.3	$ 130.5	$ 133.7	$ 137.0
Operating expenses	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6
Technical losses	$ 6.2	$ 6.3	$ 6.5	$ 6.6	$ 6.8	$ 7.0	$ 7.1	$ 7.3	$ 7.5	$ 7.7
of which, transportation	$ 3.6	$ 3.7	$ 3.7	$ 3.8	$ 3.9	$ 4.0	$ 4.1	$ 4.2	$ 4.3	$ 4.4
of which, distribution	$ 2.6	$ 2.7	$ 2.7	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 3.1	$ 3.2	$ 3.2
Armrosgasprom margin	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2
Sales price, w/o VAT	$ 126.1	$ 128.9	$ 131.9	$ 134.9	$ 138.0	$ 141.1	$ 144.4	$ 147.7	$ 151.1	$ 154.6
VAT	$ 25.2	$ 25.8	$ 26.4	$ 27.0	$ 27.6	$ 28.2	$ 28.9	$ 29.5	$ 30.2	$ 30.9
Consumer sales price	$ 151.3	$ 154.7	$ 158.2	$ 161.9	$ 165.6	$ 169.4	$ 173.2	$ 177.2	$ 181.3	$ 185.5
Consumer sales price corrected for price differential	$ 146.6	$ 150.0	$ 153.6	$ 157.2	$ 160.9	$ 164.7	$ 168.6	$ 172.6	$ 176.7	$ 180.8

2005 High Growth Scenario

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Price at border	$ 62.7	$ 72.8	$ 84.5	$ 98.1	$ 113.9	$ 116.5	$ 119.3	$ 122.1	$ 125.0	$ 128.0
Operating expenses	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6
Technical losses	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0
of which, transportation	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8
of which, distribution	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
Armrosgasprom margin	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2
Sales price, w/o VAT	$ 75.6	$ 85.7	$ 97.4	$ 111.0	$ 126.8	$ 129.5	$ 132.2	$ 135.0	$ 137.9	$ 140.9
VAT	$ 15.1	$ 17.1	$ 19.5	$ 22.2	$ 25.4	$ 25.9	$ 26.4	$ 27.0	$ 27.6	$ 28.2
Consumer sales price	$ 90.7	$ 102.8	$ 116.9	$ 133.2	$ 152.1	$ 155.4	$ 158.7	$ 162.0	$ 165.5	$ 169.0

2005 Moderate Growth Scenario

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Price at border	$ 56.6	$ 59.4	$ 62.3	$ 65.3	$ 68.5	$ 71.9	$ 75.4	$ 79.0	$ 82.9	$ 86.9
Operating expenses	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6
Technical losses	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0
of which, transportation	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8
of which, distribution	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
Armrosgasprom margin	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2
Sales price, w/o VAT	$ 69.5	$ 72.3	$ 75.2	$ 78.2	$ 81.4	$ 84.8	$ 88.3	$ 91.9	$ 95.8	$ 99.8
VAT	$ 13.9	$ 14.5	$ 15.0	$ 15.6	$ 16.3	$ 17.0	$ 17.7	$ 18.4	$ 19.2	$ 20.0
Consumer sales price	$ 83.5	$ 86.8	$ 90.2	$ 93.9	$ 97.7	$ 101.7	$ 105.9	$ 110.3	$ 114.9	$ 119.8

5. Natural Gas Tariff for Generators

2006 Update

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Price at border	$ 140.4	$ 143.9	$ 147.4	$ 151.1	$ 154.8	$ 158.6	$ 162.5	$ 166.6	$ 170.7	$ 174.9
Operating expenses	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6
Technical losses	$ 7.9	$ 8.1	$ 8.3	$ 8.5	$ 8.7	$ 8.9	$ 9.1	$ 9.3	$ 9.6	$ 9.8
of which, transportation	$ 4.6	$ 4.7	$ 4.8	$ 4.9	$ 5.0	$ 5.1	$ 5.3	$ 5.4	$ 5.5	$ 5.7
of which, distribution	$ 3.3	$ 3.4	$ 3.5	$ 3.6	$ 3.7	$ 3.8	$ 3.9	$ 3.9	$ 4.0	$ 4.1
Armrosgasprom margin	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2
Sales price, w/o VAT	$ 158.2	$ 161.8	$ 165.6	$ 169.4	$ 173.4	$ 177.4	$ 181.5	$ 185.8	$ 190.1	$ 194.6
VAT	$ 31.6	$ 32.4	$ 33.1	$ 33.9	$ 34.7	$ 35.5	$ 36.3	$ 37.2	$ 38.0	$ 38.9
Consumer sales price	$ 189.8	$ 194.2	$ 198.7	$ 203.3	$ 208.0	$ 212.9	$ 217.8	$ 222.9	$ 228.1	$ 233.5
Consumer sales price corrected for price differential	$ 185.1	$ 189.5	$ 194.0	$ 198.6	$ 203.4	$ 208.2	$ 213.2	$ 218.3	$ 223.5	$ 228.8

2005 High Growth Scenario

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Price at border	$ 131.0	$ 134.1	$ 137.2	$ 140.5	$ 143.8	$ 147.2	$ 150.7	$ 154.2	$ 157.9	$ 161.6
Operating expenses	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6
Technical losses	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0
of which, transportation	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8
of which, distribution	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
Armrosgasprom margin	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2
Sales price, w/o VAT	$ 143.9	$ 147.0	$ 150.2	$ 153.4	$ 156.7	$ 160.1	$ 163.6	$ 167.2	$ 170.8	$ 174.5
VAT	$ 28.8	$ 29.4	$ 30.0	$ 30.7	$ 31.3	$ 32.0	$ 32.7	$ 33.4	$ 34.2	$ 34.9
Consumer sales price	$ 172.7	$ 176.4	$ 180.2	$ 184.1	$ 188.1	$ 192.1	$ 196.3	$ 200.6	$ 205.0	$ 209.4

2005 Moderate Growth Scenario

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Price at border	$ 91.2	$ 95.6	$ 100.3	$ 105.2	$ 110.3	$ 115.7	$ 121.3	$ 127.2	$ 133.4	$ 139.9
Operating expenses	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6	$ 8.6
Technical losses	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0	$ 3.0
of which, transportation	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8
of which, distribution	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
Armrosgasprom margin	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2
Sales price, w/o VAT	$ 104.1	$ 108.5	$ 113.2	$ 118.1	$ 123.2	$ 128.6	$ 134.2	$ 140.1	$ 146.3	$ 152.8
VAT	$ 20.8	$ 21.7	$ 22.6	$ 23.6	$ 24.6	$ 25.7	$ 26.8	$ 28.0	$ 29.3	$ 30.6
Consumer sales price	$ 124.9	$ 130.2	$ 135.8	$ 141.7	$ 147.8	$ 154.3	$ 161.0	$ 168.1	$ 175.6	$ 183.4

6. REFERENCES

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4. Long-Term Gas Supply Security in an Enlarged Europe, Final Report ENGAGED Project, December 2003;
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6. The Energy Strategy of Russia for the Period Through 2020.

ANNEX E - A: LIST OF ACRONYMS USED IN TABLE E.2

AEO2004	*Annual Energy Outlook 2004*
AEO2005	*Annual Energy Outlook 2005*
GII	*Global Insight, Incorporated*
IEA	*International Energy Agency*
Altos	*Altos Partners*
PEL	*Petroleum Economics*
PIRA	*Petroleum Industry Research Associates, Inc*
DB	*Deutsche Bank, A.G.*
EEA	*Energy and Environmental Analysis, Inc.*
SEER	*Strategic Energy & Economic Research, Incorporated*
EVA	*Energy Ventures Analysis, Incorporated*

Reference Oil Prices Scenario (Energy Information Administration)

Calculation of World Oil Price on thermal equivalent basis (1000 cm of gas)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Original WOP (EIA), $/bbl	**$27.73**	$27.34	$26.95	$26.56	$26.17	$25.78	$25.39	**$25.00**	$25.35	$25.70	$26.05	$26.40	**$26.75**
Reference Scenario of WOP, 1000cm gas heat equivalent basis	$148.20	$146.12	$144.03	$141.95	$139.86	$137.78	$135.69	$133.61	$135.48	$137.35	$139.22	$141.09	$142.96

conversion factor: 5.34*

Calculation of Average Wellhead Price of Natural Gas in $/1000cm

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Natural gas, Average wellhead price $/cubic feet (EIA)	$ 4.98	$ 4.91	$ 4.84	$ 4.78	$ 4.71	$ 4.64	$ 4.57	$ 4.50	$ 4.43	$ 4.37	$ 4.30	$ 4.23	**$ 4.16**
Natural gas, Average wellhead price $/1000cm	$175.87	$173.45	$171.04	$168.63	$166.21	$163.80	$161.39	$158.97	$156.56	$154.15	$151.74	$149.32	$146.91

cubic feet/1000cm conversion factor: 0.02831685

Reference Oil Prices Scenario (Energy Information Administration)

Calculation of World Oil Price on thermal equivalent basis (1000 cm of gas)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Original WOP (EIA), $/bbl	$27.10	$27.45	$27.80	$28.15	**$28.50**	$28.86	$29.22	$29.59	$29.95	**$30.31**
Reference Scenario of WOP, 1000cm gas heat equivalent basis	$144.83	$146.70	$148.57	$150.44	$152.32	$154.25	$156.18	$158.12	$160.05	$161.99

conversion factor: 5.34*

Calculation of Average Wellhead Price of Natural Gas in $/1000cm

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Natural gas, Average wellhead price $/cubic feet (EIA)	$ 4.22	$ 4.29	$ 4.35	$ 4.41	$ 4.48	$ 4.54	$ 4.60	$ 4.66	$ 4.73	**$ 4.79**
Natural gas, Average wellhead price $/1000cm	$ 149.13	$ 151.36	$ 153.58	$ 155.81	$ 158.03	$ 160.26	$ 162.48	$ 164.71	$ 166.93	$ 169.16

Notes:

1) *Original forecasts by Energy Information Administrations are indicated in the table by (EIA)*
2) *Original forecasts started from 2003 and were presented for 2010, 2015, 2020, and 2025. Data for intermediate years were calculated on the basis of constant annual growth rate for each period*
3) *The 5.34 Conversion Factor used to transform the price per barrel of crude oil into the price per thousand cubic meters of natural gas was calculated as follows:*
    a. *1 metric ton of crude oil approximately equals 7.3 barrels of crude oil;*
    b. *heat content of 1 ton of oil equivalent = 10900 Kcal*
    c. *heat content of 1 bbl of oil equivalent = 10900/7.3 =.1493.15 Kcal/bbl*
    d. *heat content of 1000 cubic meters of natural gas imported to Armenia = 7980 Kcal*
    e. *heat content of 1000 cubic meters of natural gas equals heat content of 7980/1493.15 = 5.3444 bbl of crude oil*

International Energy Agency

Fuel Price Forecast (*$2002*)

Low Price

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Oil ($/bbl)	**$ 28**	**$ 27**	**$ 25**	**$ 24**	**$ 23**	**$ 22**	**$ 21**	**$ 20**	**$ 19**	**$ 18**	**$ 17**	**$ 17**	**$ 18**	**$ 18**	**$ 18**	**$ 18**
Gas (per toe* GCV)	**$119**	$115	$111	$108	$104	$101	$ 97	$ 94	$ 91	$ 88	**$ 85**	$ 86	$ 87	$ 88	$ 89	$ 90
Coal ($/ton)	**$ 35**	$ 35	$ 36	$ 36	$ 37	$ 37	$ 37	$ 38	$ 38	$ 39	**$ 39**	$ 39	$ 39	$ 40	$ 40	$ 40

Reference Price

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Oil ($/bbl)	**$ 28**	**$ 27**	**$ 26**	**$ 26**	**$ 25**	**$ 24**	**$ 24**	**$ 23**	**$ 22**	**$ 22**	**$ 21**	**$ 21**	**$ 22**	**$ 22**	**$ 23**	**$ 23**
Gas (per toe* GCV)	**$119**	$118	$117	$116	$115	$114	$114	$113	$112	$111	**$110**	$112	$114	$116	$118	$120
Coal ($/ton)	**$ 35**	$ 35	$ 36	$ 36	$ 37	$ 37	$ 37	$ 38	$ 38	$ 39	**$ 39**	$ 39	$ 39	$ 40	$ 40	$ 40

High Price

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Oil ($/bbl)	**$ 28**	**$ 28**	**$ 27**	**$ 27**	**$ 27**	**$ 26**	**$ 26**	**$ 26**	**$ 26**	**$ 25**	**$ 25**	**$ 25**	**$ 26**	**$ 26**	**$ 27**	**$ 27**
Gas (per toe* GCV)	**$119**	$121	$122	$124	$125	$127	$128	$130	$132	$133	**$135**	$138	$141	$143	$146	$149
Coal ($/ton)	**$ 35**	$ 35	$ 36	$ 36	$ 37	$ 37	$ 37	$ 38	$ 38	$ 39	**$ 39**	$ 39	$ 39	$ 40	$ 40	$ 40

toe* - Ton of oil equivalent (9000 Kcal per kg)
GCV - Gross Calorific Value

International Energy Agency

Fuel Price Forecast (*$2002*)

Low Price

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil ($/bbl)	**$ 19**	**$ 19**	**$ 19**	**$ 20**	**$ 20**	**$ 20**	**$ 20**	**$ 21**	**$ 21**	**$ 21**	**$ 21**	**$ 21**	**$ 22**	**$ 22**	**$ 22**
Gas (per toe* GCV)	$ 91	$ 92	$ 93	$ 94	**$ 95**	$ 96	$ 96	$ 97	$ 97	$ 98	$ 99	$ 99	$ 100	$ 100	**$ 101**
Coal ($/ton)	$ 40	$ 40	$ 41	$ 41	**$ 41**	$ 41	$ 42	$ 42	$ 42	$ 42	$ 43	$ 43	$ 43	$ 44	**$ 44**

Reference Price

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil ($/bbl)	**$ 23**	**$ 24**	**$ 24**	**$ 25**	**$ 25**	**$ 25**	**$ 26**	**$ 26**	**$ 27**	**$ 27**	**$ 27**	**$ 28**	**$ 28**	**$ 29**	**$ 29**
Gas (per toe* GCV)	$ 122	$ 124	$ 126	$ 128	**$ 130**	$ 132	$ 134	$ 136	$ 138	$ 140	$ 142	$ 144	$ 147	$ 149	**$ 151**
Coal ($/ton)	$ 40	$ 40	$ 41	$ 41	**$ 41**	$ 41	$ 42	$ 42	$ 42	$ 42	$ 43	$ 43	$ 43	$ 44	**$ 44**

High Price

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil ($/bbl)	**$ 28**	**$ 28**	**$ 29**	**$ 29**	**$ 30**	**$ 31**	**$ 31**	**$ 32**	**$ 32**	**$ 33**	**$ 33**	**$ 34**	**$ 35**	**$ 35**	**$ 36**
Gas (per toe* GCV)	$ 152	$ 155	$ 159	$ 162	**$ 165**	$ 168	$ 172	$ 175	$ 179	$ 182	$ 186	$ 189	$ 193	$ 197	**$ 201**
Coal ($/ton)	$ 40	$ 40	$ 41	$ 41	**$ 41**	$ 41	$ 42	$ 42	$ 42	$ 42	$ 43	$ 43	$ 43	$ 44	**$ 44**

toe* - Ton of oil equivalent (9000 Kcal per kg)
GCV - Gross Calorific Value

ANNEX E - D: PRIMARY FUEL PRICES FORECAST BY INTERNATIONAL ENERGY ADMINISTRATION

Fuel Price Forecast ***($2003)***																
Low Price																
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Oil ($ per 1000 cm gas heat euqivalent)	$ 154	$ 146	$ 139	$ 132	$ 126	$ 120	$ 114	$ 108	$ 103	$ 98	$ 93	$ 95	$ 96	$ 98	$ 99	$ 101
Gas ($ per 1000 cm of gas)	$ 109	$ 105	$ 101	$ 98	$ 95	$ 92	$ 89	$ 86	$ 83	$ 80	$ 78	$ 78	$ 79	$ 80	$ 81	$ 82
Gas/Oil Price Ratio on Thermal Equivalent Basis	0.707	0.718	0.730	0.742	0.754	0.767	0.779	0.792	0.805	0.818	0.832	0.827	0.823	0.819	0.815	0.811
Reference Price																
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Oil ($ per 1000 cm gas heat euqivalent)	$ 154	$ 149	$ 145	$ 141	$ 137	$ 133	$ 129	$ 126	$ 122	$ 119	$ 115	$ 117	$ 119	$ 121	$ 123	$ 126
Gas (per 1000 cm of gas)	$ 109	$ 108	$ 107	$ 106	$ 105	$ 104	$ 104	$ 103	$ 102	$ 101	$ 100	$ 102	$ 104	$ 105	$ 107	$ 109
Gas/Oil Price Ratio on Thermal Equivalent Basis	0.707	0.722	0.737	0.753	0.769	0.785	0.801	0.818	0.836	0.853	0.871	0.871	0.870	0.869	0.869	0.868
High Price																
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Oil ($ per 1000 cm gas heat euqivalent)	$ 154	$ 152	$ 150	$ 148	$ 147	$ 145	$ 143	$ 142	$ 140	$ 139	$ 137	$ 140	$ 142	$ 145	$ 147	$ 150
Gas (per 1000 cm of gas)	$ 109	$ 110	$ 111	$ 113	$ 114	$ 116	$ 117	$ 119	$ 120	$ 122	$ 123	$ 126	$ 128	$ 131	$ 133	$ 136
Gas/Oil Price Ratio on Thermal Equivalent Basis	0.707	0.724	0.742	0.760	0.778	0.797	0.816	0.836	0.856	0.877	0.898	0.900	0.901	0.903	0.905	0.906

-D: Primary Fuel Prices Forecast by International Energy Administration

Fuel Price Forecast ***($2003)***															
Low Price															
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Oil ($ per 1000 cm gas heat euqivalent)	$ 103	$ 104	$ 106	$ 108	$ 110	$ 111	$ 112	$ 113	$ 114	$ 115	$ 116	$ 117	$ 118	$ 120	$ 121
Gas ($ per 1000 cm of gas)	$ 83	$ 84	$ 85	$ 86	$ 87	$ 87	$ 88	$ 88	$ 89	$ 89	$ 90	$ 90	$ 91	$ 92	$ 92
Gas/Oil Price Ratio on Thermal Equivalent Basis	0.806	0.802	0.798	0.794	0.790	0.787	0.785	0.782	0.779	0.777	0.774	0.771	0.769	0.766	0.764
Reference Price															
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Oil ($ per 1000 cm gas heat euqivalent)	$ 128	$ 130	$ 132	$ 135	$ 137	$ 139	$ 141	$ 143	$ 145	$ 148	$ 150	$ 152	$ 154	$ 157	$ 159
Gas (per 1000 cm of gas)	$ 111	$ 113	$ 115	$ 117	$ 119	$ 120	$ 122	$ 124	$ 126	$ 128	$ 130	$ 132	$ 134	$ 136	$ 138
Gas/Oil Price Ratio on Thermal Equivalent Basis	0.867	0.867	0.866	0.866	0.865	0.865	0.865	0.865	0.865	0.865	0.866	0.866	0.866	0.866	0.866
High Price															
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Oil ($ per 1000 cm gas heat euqivalent)	$ 153	$ 156	$ 159	$ 162	$ 165	$ 168	$ 171	$ 174	$ 177	$ 180	$ 184	$ 187	$ 190	$ 194	$ 197
Gas (per 1000 cm of gas)	$ 139	$ 142	$ 145	$ 148	$ 151	$ 154	$ 157	$ 160	$ 163	$ 166	$ 169	$ 173	$ 176	$ 180	$ 183
Gas/Oil Price Ratio on Thermal Equivalent Basis	0.908	0.910	0.911	0.913	0.915	0.916	0.918	0.919	0.920	0.922	0.923	0.924	0.926	0.927	0.929

Price of gas for industry for 2005 (w/o VAT)

New Price Zone	Region	Previous Price (price zone)	New Price	Increase, %
I	Yamalo-Nenetsky Autonomous Region	526 (0)	619	17,68
II	Khanty-Mansijsky Autonomous Region	634 (1)	745	17,51
III	Tyumen	739 (2)	879	18,94
IV	Udmurtiya Kurgan Perm	828 (3) 828 (3) 828 (3)	985	18,96 18,96 18,96
IV A	Komi Orengurg Astrakhan	739 (2) 739 (2) 739 (2)	923	24,90
V	Bashkiriya Arkhangelsk Sverdlovsk Tomsk	828 (3) 828 (3) 828 (3) 828 (3)	1005	21,38 21,38 21,38 21,38
VI	Kalmykiya Kirov Omsk Chelyabinsk Mari-El Tatarstan Chuvashiya	828 (3) 828 (3) 828 (3) 828 (3) 871 (4) 871 (4) 871 (4)	1033	24,76 24,76 24,76 24,76 18,60 18,60 18,60
VII	Novosibirsk Mordoviya Vologda Nizhny Novgorod Penza Samara Uljanovsk Yaroslavl	828 (3) 871 (4) 871 (4) 871 (4) 871 (4) 871 (4) 871 (4) 871 (4)	1040	25,60 19,40 19,40 19,40 19,40 19,40 19,40 19,40
VIII	Vladimir Ivanovo Kostroma Saratov Kareliya St. Petersburg and region Lipetsk Tambov Tver	871 (4) 871 (4) 871 (4) 871 (4) 912 (5) 912 (5) 912 (5) 912 (5) 912 (5)	1088	24,91 24,91 24,91 24,91 19,30 19,30 19,30 19,30 19,30

New Price Zone	Region	Previous Price (price zone)	New Price	Increase, %
IX	Altay	912 (5)	1119	22,70
	Belgorod	912 (5)		22,70
	Bryansk	912 (5)		22,70
	Volgograd	912 (5)		22,70
	Voronezh	912 (5)		22,70
	Kaluga	912 (5)		22,70
	Kemerovo	912 (5)		22,70
	Kursk	912 (5)		22,70
	Moscow and region	912 (5)		22,70
	Orel	912 (5)		22,70
	Pskov	912 (5)		22,70
	Ryazan	912 (5)		22,70
	Smolensk	912 (5)		22,70
	Tula	912 (5)		22,70
X	Kaliningrad	937 (6)	1154	23,16
	Rostov	937 (6)		23,16
XI	Adygeya	937 (6)	1160	23,80
	Dagestan	937 (6)		23,80
	Ingushetiya	937 (6)		23,80
	Kabardino-Balkariya	937 (6)		23,80
	Karachayevo-Cherkessiya	937 (6)		23,80
	Severnaya Osetiya	937 (6)		23,80
	Chechnya	937 (6)		23,80
	Krasnodar	937 (6)		23,80
	Stavropol	937 (6)		23,80

Source: Decree of the Federal Tariff Service #229-e/15 of December 3, 2004 “On Wholesale Price of Gas Produced by OJSC Gasprom and its Affiliated Companies to Sell to Customers”

APPENDIX F:

Results of Detailed Analysis

Armenian Power Sector 2006 Least Cost Generation Plan

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1. APPENDIX F-1: SCREENING ANALYSIS

1. INTRODUCTION

Screening analysis is an essential part of the overall modeling process. Screening reduces the number of supply options to be considered at the stage of computer modeling, reducing computational time and increasing the optimization accuracy. 2005 LCGP included a screening analysis of several new technologies.

Also, to gain a better understanding of the proposed life extension and rehabilitation/ reconfigured projects, they were compared to new technology alternatives.

2. ANPP OPERATION AND LIFE EXTENSION, AND HRAZDAN #5 RECONFIGURATION OPTIONS

Two projects related to existing facilities were considered as potential options for 2005 LCGP analysis. These projects are included in Table 1.

Table 1 – Life extension and Unit Reconfiguration Projects

Unit	***Gross Capacity after Life Extension/ Reconfiguration, MW***	***Useful Life after rehabilitation, years***	***Unit Cost, $/kW (Y2005)***
Thermal Power Project			
Hrazdan Unit# 5 Gas Turbine Reconfiguration	*440*	*30*	*$320*
Nuclear Power Plant			
ANPP Continued Operation through 2015	*400*	*20*	*$400*
ANPP Life Extension through 2035			*$2,539*

As indicated above, the life extension of ANPP is more expensive due to substantially higher costs associated with unit's life extension and spent nuclear fuel disposal.

3. NEW POWER TECHNOLOGIES

In order to develop an optimal system expansion plan, the following new technologies (projects) were considered in the planning process:

- New Gas-Fired Combined Cycle Power Plants (225 MW and 400 MW size)
- Gas-Fired Gas Turbine (75 MW size)
- Nuclear Units (AP-1000 (USA), 2xCANDU 6 (Canada), ACR-1000 (Canada), VVER-1000 (Russia), EPR (France/Germany))
- Hydro Plants (70 MW at Shnokh, 140 MW at Megri and 68 MW at Lori-Berd)

The construction of the hydro power plants has been noted and discussed in the Energy Sector Development Strategies in the Context of Economic Development in Armenia. Due to their strategic nature, the cost of these units may not be relevant for the process of

optimal technology mix identification. However, they were included in the screening analysis only for illustrative purposes.

4. SCREENING ANALYSIS METHODOLOGY

The screening analysis serves to reduce the number of resource alternatives that need to be included in the optimization phase of the least cost generation planning process.

The screening process takes into account levelized *capital costs*, both *fixed and variable O&M costs*, expressed in dollars per kW at various capacity factors for each alternative technology/project. The objective is to select the lowest cost units within specific bands of capacity factors as candidate resources for inclusion in the optimization phase of the study.

It is important to recognize that screening analysis is performed only as a preliminary step of overall optimization process and its primary goal is to reduce computational time rather than providing an answer for the technology to be chosen for further and more detailed considerations.

4.1. PARTICULARITIES OF LCGP 2005 METHODOLOGY

The previous Least Cost Generation Plans were based on universal values of discount rates and financial costs rates, expressed as percentage of total needed capital, which were the same across the whole set of technologies. And then analyzed scenarios differed by WACC and discount rate. The LCGP 2005 is based on a different methodology. Initially, three different scenarios were developed for the weighted average cost of capital to be used as discount rates in optimization process and to calculate the amount of annual financial costs for screening analysis. Three values for the weighted average cost of capital were derived from the analysis of the current conditions of financial markets in Armenia and abroad: 12.7%, 14.9% and 16.7% for the low, reference and high scenarios respectively. These WACC values were associated with the cost of debt of 8.48%, 8.48% and 12.46%. As it became known later, Western financial organizations provided low interest loans to promote construction of nuclear technologies [1], for which the interest rate could be as low as 5%. Potential availability of such loans along with their scale, which could cover full cost of construction of a new nuclear power plant, changed the approach to screening and optimization. Due to the mentioned fact it became obvious, that even in one scenario different combinations of different WACC and discount rates values might be applied for different technologies, since, for example, at the moment it is known that cheap money at the 0.75% interest will be available for construction of one CCGT at Yerevan TPP, and there is no indication that similarly cheap money will be available for other thermal units. Therefore, in our calculations we considered different combinations of WAAC for different technologies under the framework of one scenario.

4.2. CHANGES IN APPROACH

Substantial change in the natural gas price for generation in 2006, enacted by the PSRC, changed the relative economics of different generation technologies and also raised the degree of uncertainty associated with future development of the gas price. Though it was announced that the price at the border would remain constant during 2006-2008, it is unclear what potential rate increase may materialize. It is clear that the huge discrepancy in price between the border of Armenia ($110 per ths. cm) and the Western border of Russia ($230 per ths. cm) may not last for long.

The other important input parameter which might also change from a long-term prospective is the cost of capital. During late 2005 early 2006 the increase in cost of financial resources/ capital in international markets has become more evident. The growth of nuclear fuel price that would follow the path of the crude oil price (not to the same level of severity) looks more likely now than it appeared in 2005.

For these reasons the main issue for screening in LCGP 2006 Update was not a reduction of alternatives for optimization, but assessment of the ranges of important input parameters, such as fuel price and cost of capital, which preserve optimal generation strategy. In other words, screening for LCGP 2006 Update was performed to demonstrate stability of the optimal generation strategy, or, to conduct preliminary sensitivity analysis.

To perform this task, several changes were applied to the screening approach for 2006 LCGP update:

- base case assessments were calculated for new natural gas price;
- uniform weighted average costs of capital were applied to all generation technologies across the same scenario;
- sensitivity calculations included variations of natural gas price, weighted average cost of capital and nuclear fuel price growth rates.

To resolve the tasks described above, appropriate changes were applied to input data.

5. INPUT DATA

Updated data used in screening analysis in LCGP 2006 Update are shown in Tables 2 and 3. Most of the data coincide with the ones used in LCGP 2005. The differences include fuel cost, discount rates, overnight cost of capital with interest during construction and escalation rate of fuel costs.

Table 2 presents the summary of data used to evaluate newly proposed projects at the screening level. Table 3 presents the summary of data used to evaluate life extension, rehabilitation/reconfiguration projects at the screening level.

Table 2 Screening Analysis Input – New Projects

TECHNOLOGY / *FEATURES*	**Combined Cycle – Gas - Fired (1)**	**Reconfiguration**	**Combined Cycle – Gas – Fired (2)**	**Gas Turbine –**	**Nuclear Unit (1)**	**Nuclear Unit (2)**	**Nuclear Unit (3)**	**Nuclear Unit (4)**	**Nuclear Unit (5)**	**Hydro Power Plant (1)**	**Hydro Power Plant (2)**	**Hydro Power Plant (3)**
Type/Project	Proxy CC Turbine	Hrazdan 5	Yerevan TPP	Proxy Gas Turbine ---	AP-1000	2xCANDU 6	ACR 1000	VVER-1000 (Rus)	EPR	Shnokh	Megri	Lori-Berd
Gross Maximum Capacity (MW)	400	440	225	75	1117	1347	1125	950	1600	70	140	68
Maximum Annual Availability[1] %	100%	100%	100%	100%	100%	100%	100%	100%	100%	44%	63%	38%
Auxiliary Power Consumption %	3%	8%	8%	1%	3.2%	7.5%	6.2%	10.4%	5%	1%	1%	1%
Net Heat Rate (@ 100%	6075	8333	6390	9220	10340	10452	9830	11078	9478	N/A	N/A	N/A
(Btu/kWh) 75%	6257	8568	6581.4	9314	10340	10452	9830	11078	9478			
50%	6803	9497	7156.7	10417	10340	10452	9830	11078	9478			
25%	7957	11997	8370.4	14199	10340	10452	9830	11078	9478			
Construction (years)	2.5	1.5	2.5	2	6	7	5	6	5	5	5	5

[1] For new hydro plants this parameter is driven by average multi-year water conditions, for other technologies there exist practical examples of operation for similar types of plants.

Construction Pattern (%/yr)	30/60/10	60/40	30/60/10	50/50	10/20/20/20/20/10	8/21/27.1/19.6/12/7.2/5.1	8/22/29/21/20	1/9/17/17/33/23	10/22/28/20/20	30/30/20/10/10	30/30/20/10/10	30/30/20/10/10
Discount Rate (%)	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48
Overnight Capital Cost ($/kW)	600	320[2]	635	468	1376	1475.00	1475.00	1500	1864.00	1858	1000	1606
Overnight Capital Cost Incl. IDC ($/kW)	693	347	733	508	1843.21	2146.78	1857.23	1862.68	2357.31	2504	1348	2164
Decommissioning Cost ($2005)					$231 million	$298 million	$233 million	$214 million	$447 million			
O&M Cost: - Fixed ($/kW/yr) - Variable (non-fuel)[3] ($/MWh) - Other ($/kW)	14.0 0.87	14.0 0.87	15.04 0.96	10.5 0.8	65.0 0.00	70.7 0.00	69.9 0.00	63.00.00	36.1 0.00	11.4	13.9	13.9
Y 2005 Fuel Cost ($/MMBtu), Spent Nuclear Fuel Disposal Cost ($/MMBtu),	4.58	4.58	4.58	4.58	0.445 0.11	0.164 0.108	0.366 0.1058	0.4327 N. D.*	0.5130 N. D.*	N/A	N/A	N/A
Escalation %/yr	2.39%	2.39%	2.39 %	2.39%	3%	3%	3%	3%	3%			
Life of Unit, yrs	30	30	30	30	60	60	60	50	60	40	40	40

*) No data were available at the time of preparation of this report.

Table 3 Screening Analysis Input – Proposed Life extension and Reconfiguration Projects

TECHNOLOGY / *FEATURES*	Reconfiguration	Continued Operation through 2015	Life Extension through 2035
Type/Project	Hrazdan 5	ANPP	ANPP
Gross Maximum Capacity MW	440	380	380
Auxiliary Power Consumption (%)	8	8	8
Net Heat Rate (@	8333	11374	11374
(Btu/kWh) 100%	8568	11374	11374
75%	9497	11374	11374
50%	11997	11374	11374
25%		11374	11374
Construction (years)	1.5	5	5
Construction Pattern (%)	60/40	10/20/20/20/20/10	10/20/20/20/20/10
Discount Rate (%)	8.48	8.48	8.48
Overnight Capital Cost ($/kW)	320	400	2,539
Overnight Capital Cost Incl. IDC ($/kW)	347	438	2,629
O&M Cost: - Fixed ($/kW/yr) - Variable (non-fuel) ($/MWh)	14.0 0.87	47.40 0.35	47.40 0.35
Y2005 Fuel Cost ($/MMBtu),	4.58	0.53	0.53
Spent Nuclear Fuel Disposal Cost ($/MMBtu)	N/A	N/A*	N/A*
Escalation %/yr	2.39%	3%	3%
Life of Unit after Rehab., yrs	30	10**	20**

*) Accounted in Variable Operating and Maintenance cost

**) Spent Nuclear Fuel Disposal cost will continue over 50 years after decommissioning of the unit

6. SCREENING ANALYSIS RESULTS

The results of screening evaluation performed on the basis of updated data are presented in Figure 1. Several important changes in comparison with the similar screening results of LCGP 2005 can be noted from the graphs.

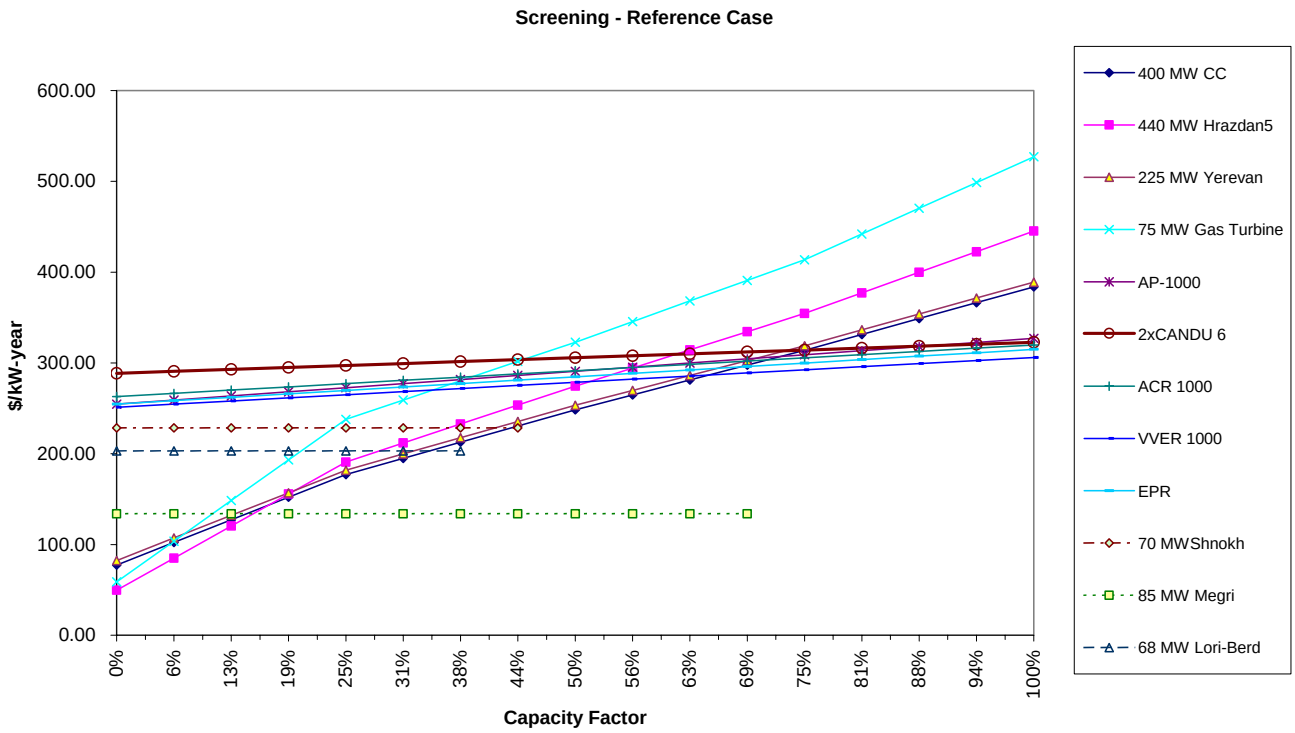
First and foremost, with updated prices of natural gas, the economic effectiveness of new nuclear technologies has become more profound. As the graph shows, operation of practically all nuclear technologies beyond 75% capacity factor is cheaper than operation of any thermal generating technology.

Second, Hrazdan 5 turns into a viable peaking technology – the costs of its operation below 15% capacity factor are the lowest on the system.

New hydro power plants turn into reasonable technologies and from the stand point of economics may be considered as competitive technologies.

Regarding the first statement it is clear that the growth in natural gas price has caused a profound change in relative economics between nuclear and thermal technologies. And this change should be considered as a correction of economic discrepancy between the cost of electric power produced in thermal and nuclear plants, which existed due to artificially low price of natural gas in Armenia.

Figure 1: Results of the screening analysis for the reference scenario



The profound change in economics of hydro generation is also explained by very simple fact: the reference case in 2006 LCGP Update assumes the same weighted average cost of capital at 8.48% for all new generation, regardless of the type of technology. The LCGP 2005 considered in its reference case 14.9% WACC for new hydro and thermal technologies and 8.48% for new nuclear technologies. The results of sensitivity analysis

will demonstrate that should such a difference in WACC occur, new hydro power plants would lose all their competitive advantages altogether.

Also, similar to the LCGP 2005, the conclusion that at 8.48% WACC and higher than 75% capacity factor, all nuclear technologies produce a very similar costs in a range of $292-314/MW/year also holds.

Yet another fact is well illustrated by the graph, pertaining to relative economics of different generating technologies. Base-load power plants are characterized by high fixed costs associated with high capital expenses for their construction, and relatively low variable costs. Peaking technologies, on the contrary, have low fixed and high variable costs, while cycling technologies are characterized by relatively low fixed and moderate variable costs. As indicated in the graph, the units with for 0-15% capacity factor are considered as peaking units, 15-75% as intermediate, and above 75% capacity factor as base load units.

7. SENSITIVITY ANALYSIS

Several important questions were analyzed for sensitivity purposes including:

- the range of potential growth rates of nuclear fuel prices;
- low growth rate of fossil fuel prices;
- other scenarios for weighted average cost of capital.

The response to these questions are discussed below.

Detailed analysis of the nuclear fuel market is beyond the scope of this study. However, it is prudent to examine the fact that even if the nuclear fuel price grows much faster than it was anticipated in the LCGP 2005, it would not change the identified optimal strategy. For this reason the escalation rate for nuclear fuel price was doubled from 3% to 6% per annum. Although, taking into account the peculiarities of the international nuclear fuel market, this assumption may look too radical. Results of this sensitivity analysis are presented in Figure 2. As shown, the 6% growth in nuclear fuel price makes the competitive advantage of the nuclear technologies less profound. However, at high capacity factor, nuclear remains the more preferable solution. As indicated in Figure 2, under doubled growth rates of nuclear fuel the power plant design based on 2xCANDU6 reactors become more preferable as compared with other technologies, since it has the lowest variable costs for generation.

During the preparation of the LCGP 2006 Update, much uncertainty remains associated with the ranges of potential variations of natural gas price. Some optimists believe that a high growth rate scenario may not materialize in the future. Figure 3 addresses this assumption. This sensitivity graph was developed with an absolutely unrealistic assumption that there would not be any growth in natural gas price. In other words, escalation rate of the natural gas price was set to zero for this sensitivity calculations The results are self explanatory: the only thermal technology which turns out to be efficient under such conditions is the 225 MW CCGT built at Yerevan site with preferable financing provided by JBIC at 0.75% per annum. It is interesting to note that closer to 100% capacity factor the difference between nuclear and CCGT is indistinguishable.

Figure 2: Sensitivity Analysis – Doubled Growth Rate of Nuclear Fuel Price

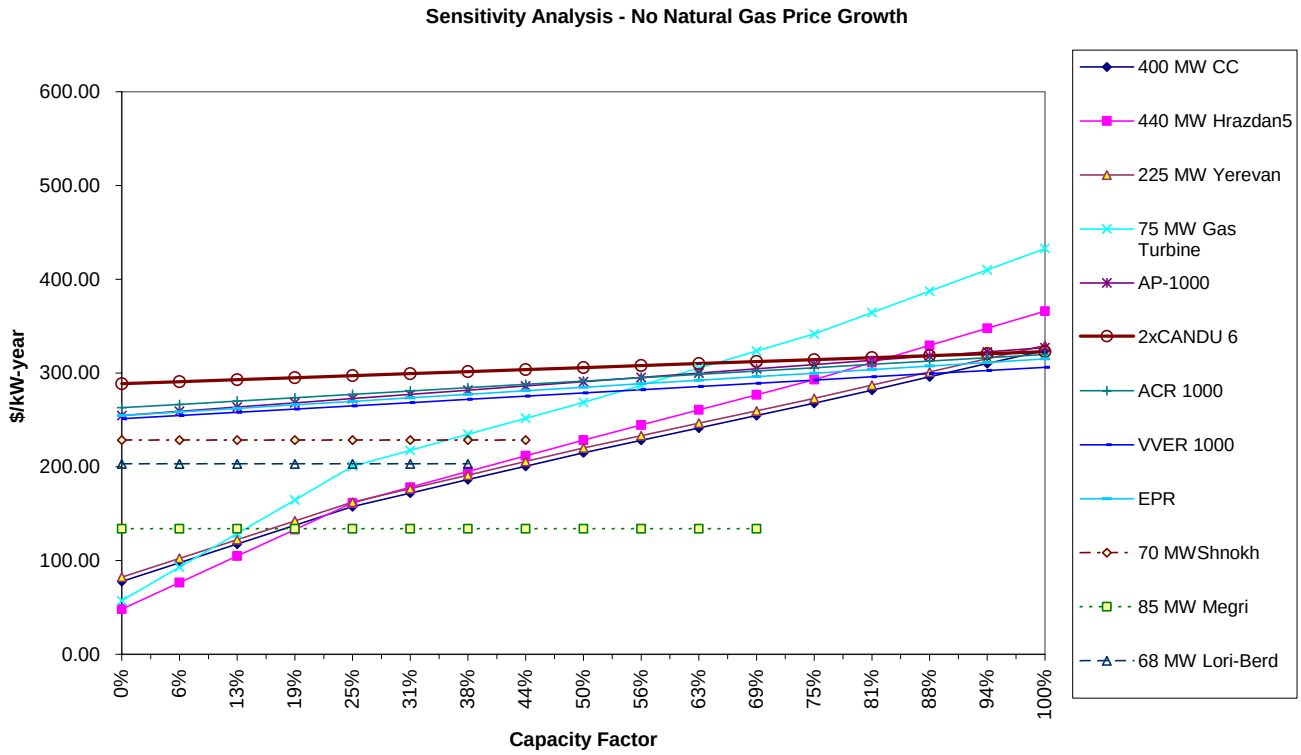
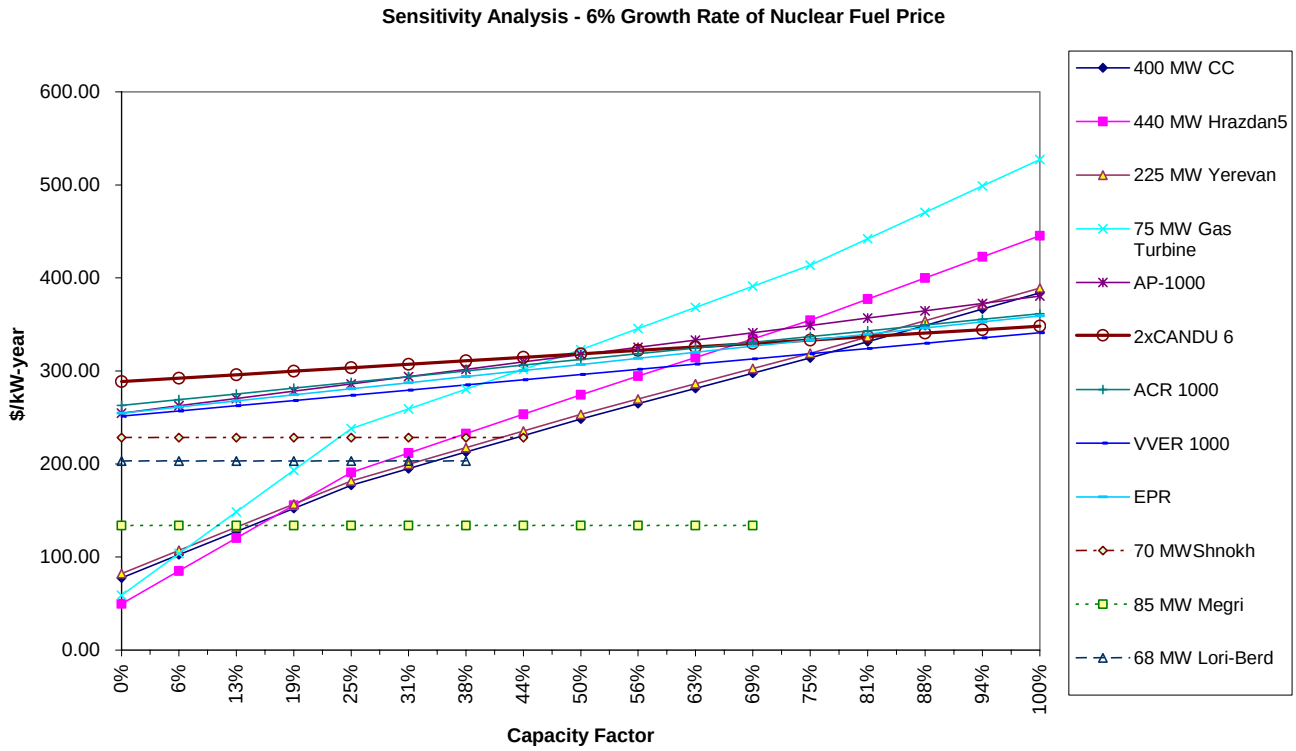


Figure 3: Sensitivity Analysis – No Natural Gas Price Growth



The results of sensitivity analysis for various weighted average cost of capital are presented in Figures 4 to 6. Figures 4 and 5 present screening curves for 12.7% and 14.9% WACC respectively, while figure 6 illustrates the situation considered as a reference scenario in LCGP 2005 (i.e. WACC to be equal to 8.48% for nuclear technologies, and 14.9% for new thermal and hydro technologies) .

As presented in the graphs, increased weighted average cost of capital removes the nuclear technologies out of the range of optimal generation options. This is caused by higher capital costs and longer construction periods, which with accrued interest during construction drives the nuclear costs up much faster than the costs of other technologies.

Figure 4: Screening Curves at 12.7% WACC for all new technologies.

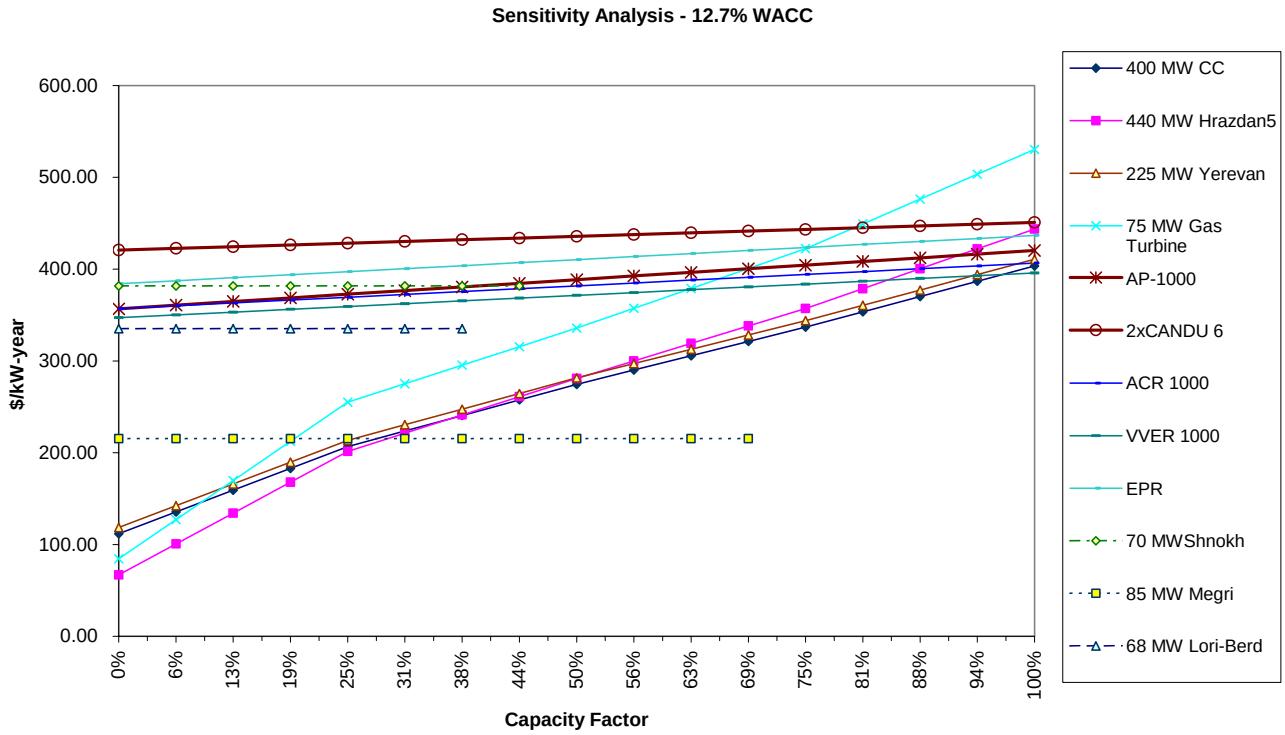


Figure 5: Screening Curves at 14.9% WACC for all new technologies.

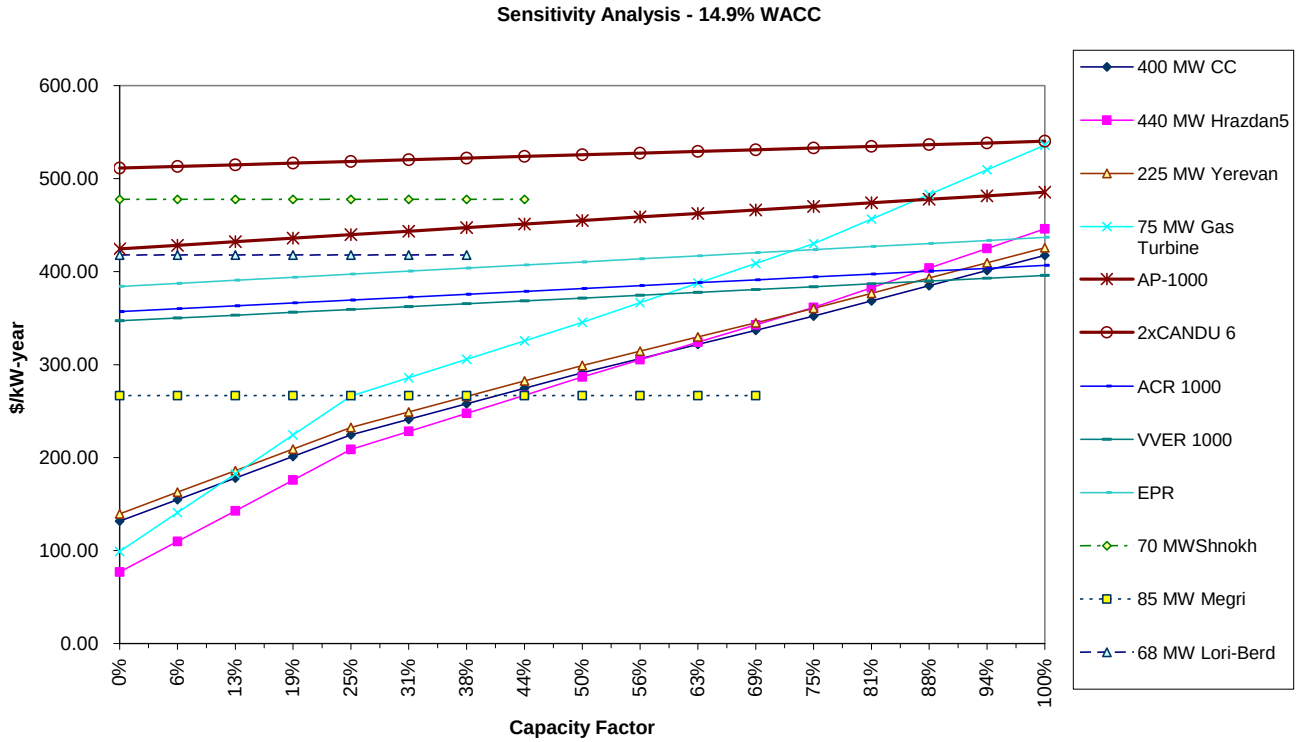
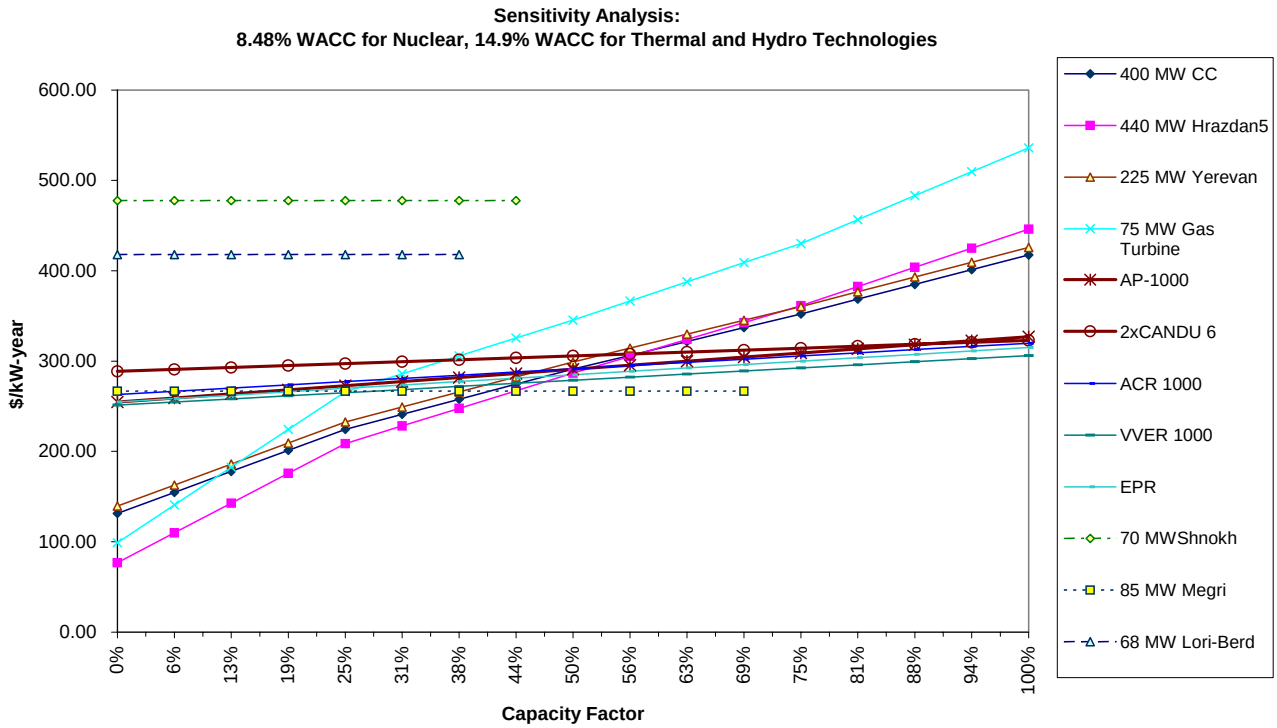


Figure 6: Screening Curves for different weighted average costs of capital for different technologies.



8. SUMMARY AND CONCLUSIONS OF SCREENING ANALYSIS

8.1 Least-Cost Alternatives

The conclusions regarding optimal generating technologies inferred in LCGP 2005 have been confirmed by the recent analysis, performed on the basis of updated input data.

- Nuclear projects are the most economical options for the base-load generation (total of 5);
- All life extensions and reconfiguration projects remain efficient solution (total of 2);
- New gas-fired alternatives are the most efficient options as cycling and peaking technologies (total of 3);
- The optimal generation strategy based on the mix of technologies chosen in the described above order of priority has become substantially more stable against potential variations in external parameters.

7.2 Strategic Alternatives

Strategic options considered in LCGP 2005 may become even economically justified, depending on the cost of their financing. However, these strategic options due to substantial limitations of their availability should not be considered as an adequate substitute for base load generation needs or ANPP's replacement.

2. APPENDIX F-2: IMP MODELING SUMMARY RESULTS

Sixteen cases were selected for further analysis and evaluation. The base case scenario assumed ANPP retirement at the end of 2015, while the alternative case assumed ANPP life extension through 2035. The first 7 cases evaluated the impact of various variables that can potentially have a significant impact on power generation costs. It was also assumed that the proposed 225 MW Yerevan unit will receive soft loans and grants for its construction. The remaining 9 cases were evaluated to assess the impact of certain imposed conditions on the outcome. Case 8 assumes restriction on new nuclear plant construction, Case 9 – restriction on new thermal plants (except JBIC funded 225 MW Yerevan CCGT), Case 10 assesses impact of retiring old thermal plants by 2020, Case 11 assumes that proposed 225 MW Yerevan plant would not receive soft loans and grants, Case 12 evaluates the impact of imposing a reserve margin of 25% rather than 30% on the system, Cases 13 and 14 addresses the impact of 0% and 1 % demand growth case respectively. Case 15 assumes 30 - year life for new nuclear projects instead of 50-60 designed life, and Case 16 evaluates the impact of constructing a number of hydro projects as a strategy to diversify fuel sources. The 16 cases with various electricity demand, fuel costs, WACC and other factors are shown in Table 1.

Table.1

Studied Cases

No	Case	Demand Forecast			Fuel Price Forecast	WACC Forecast			Special Parameters
		Base	High	Low	New 2006	Base	High	Sensitivity	
1	BNB	X			X	8.48%			
2	BNH	X			X		12.70%		
3	BNS	X			X			14.90%	
4	HNB		X		X	8.48%			
5	HNH		X		X		12.70%		
6	LNB			X	X	8.48%			
7	LNH			X	X		12.70%		
8	No_Nuce	X			X	8.48%			No Nuclear Technology
9	BNB_NT	X			X	8.48%			No New Thermal (except YerevanJBIC)
10	TR	X			X	8.48%			Termal Retirement
11	YC	X			X	8.48%			No JBIC loan
12	25%	X			X	8.48%			25% Reserve Margine
13	D0%	X			X	8.48%			0% Demand growth
14	D1%	X			X	8.48%			1% Demand growth
15	LT	X			X	8.48%			30 years lifetime of new NPP
16	SMP	X			X	8.48%			Strategic Projects

Note: The Case Acronyms (BNB, LNH, etc.) represent the forecasts (Base, High, Low, Sencitivity or New 2006), for Demand, Fuel Price, and WACC

Some approaches implemented in LCGP 2005 and 2006 studies are different from the methods used in 2000 and 2002 studies.

The major difference pertains to the analysis of ANPP operation and life extension options (2016 and 2036 for LCGP 2005). In LCP 2000 and 2002 studies an alternative scenario was calculated in order to compare overall system costs during the planning horizon for the base and alternative cases. The preferable option for ANPP life extension was defined based on comparison of the above results derived from the model.

The selection of economically reasonable ANPP life extension option in LCGP 2005 study was achieved by including both options as separate potential generation alternatives, within the scope of the optimization. The results indicate that the ANPP life extension after 2016 with the assumed costs associated with safety improvements and additional spent nuclear fuel (SNF) disposal is not a feasible economic alternative. However, it should be noted that if these costs are reduced through low cost loans and or grants life extension may become a viable option,

In the following pages the results of analysis for each case are presented.

CASE 1. BNB SCENARIO

Table F.1. Capacity Additions and Retirements for BNB Scenario

Case	Year	2008	2009	2016
BNB	Capacity Addition	225 MW Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP 2016

Figure F.1.1 Generating Capacity Mix by Fuel Type

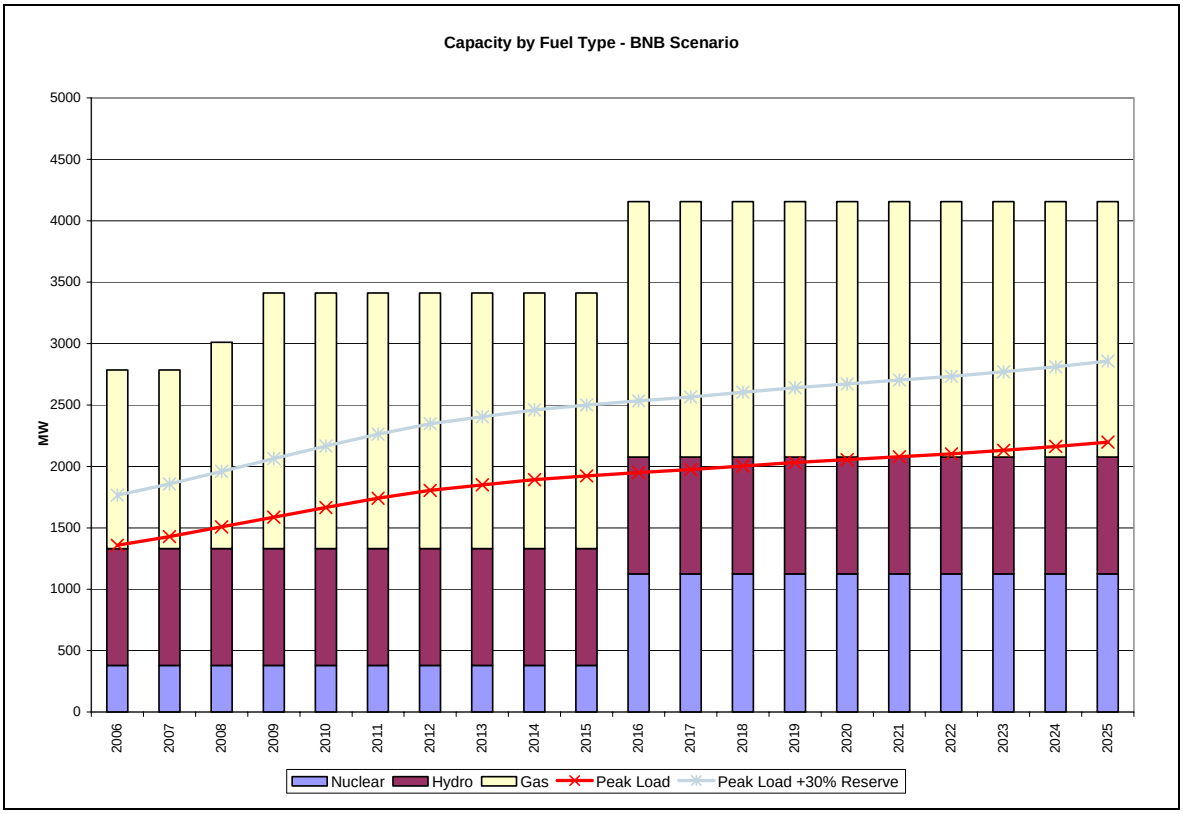


Figure F.1.2. Energy Supply by Fuel Type

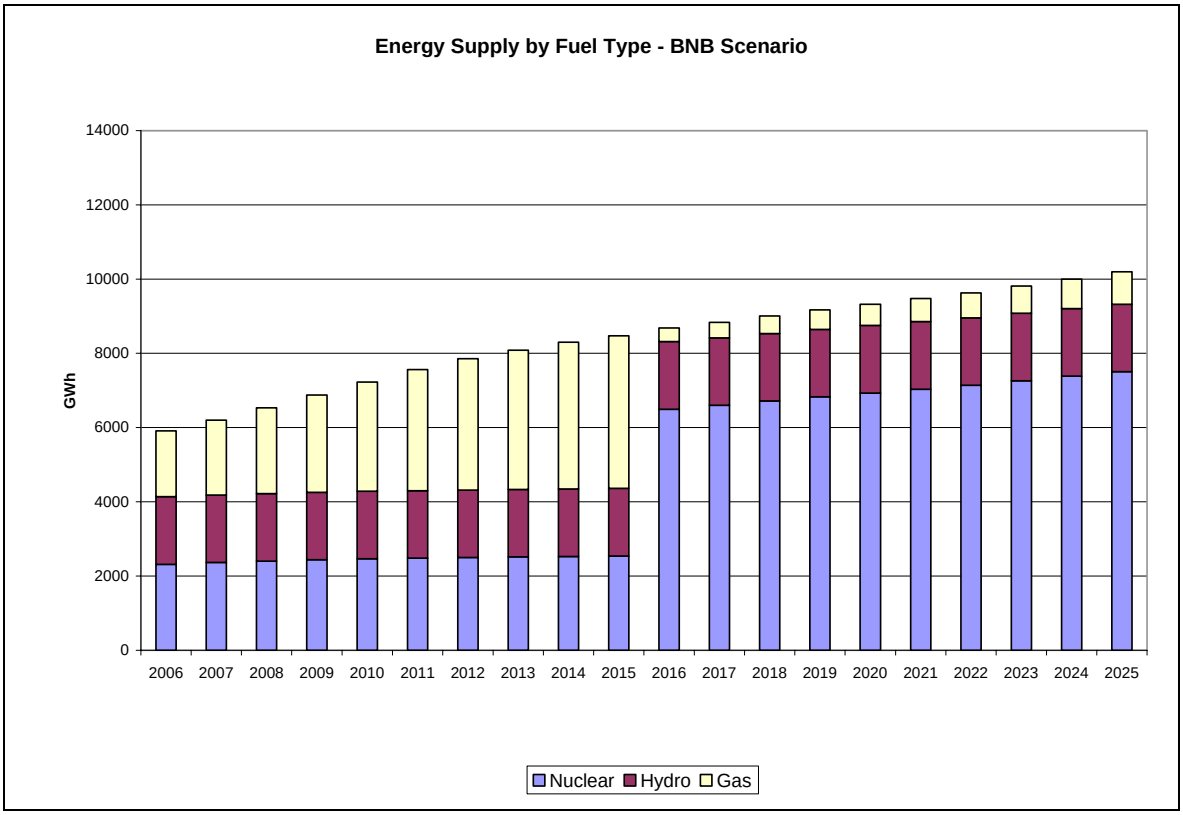
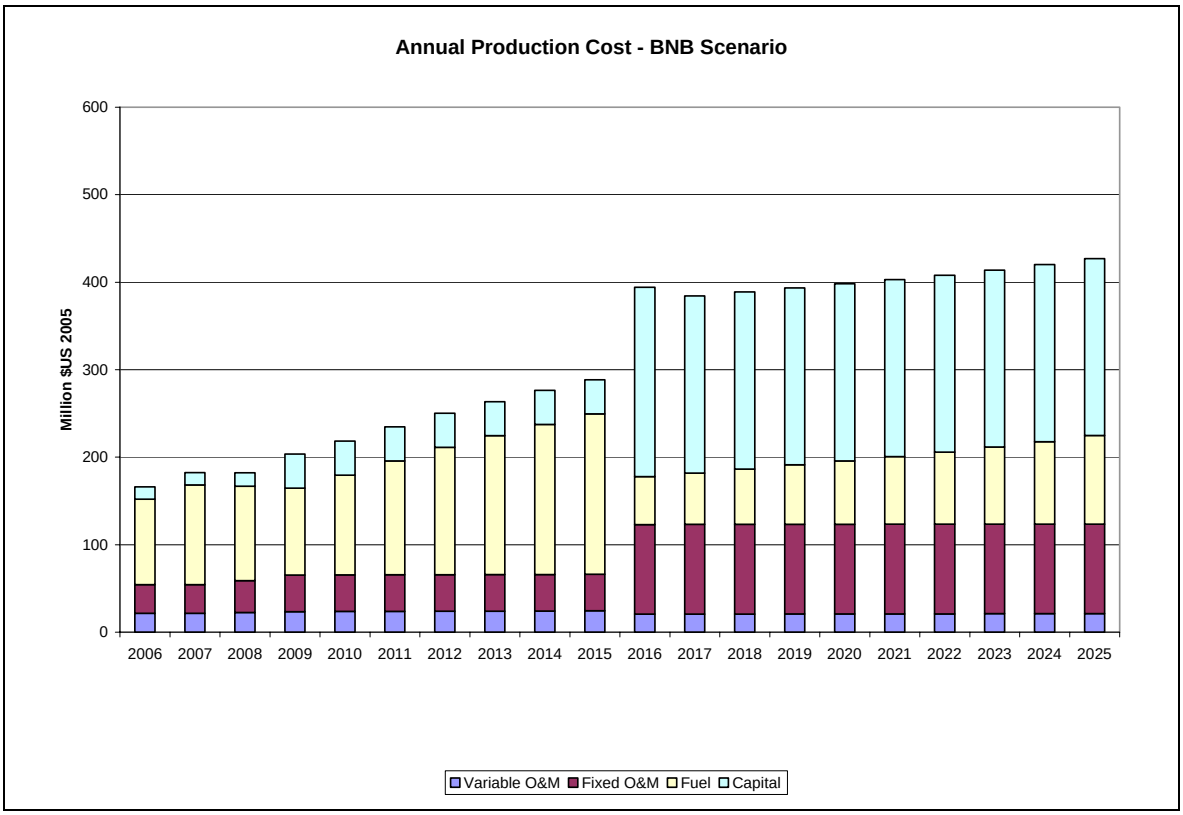


Figure F.1.3. Annual Costs ($2005) for Generation



CASE 2. BNH SCENARIO

Table F.2. Capacity Additions and Retirements for BNH Scenario

Case	Year	2008	2016
BNH	Capacity Addition	Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP 2016

Figure F.2.1 Generation Capacity Mix by Fuel Type

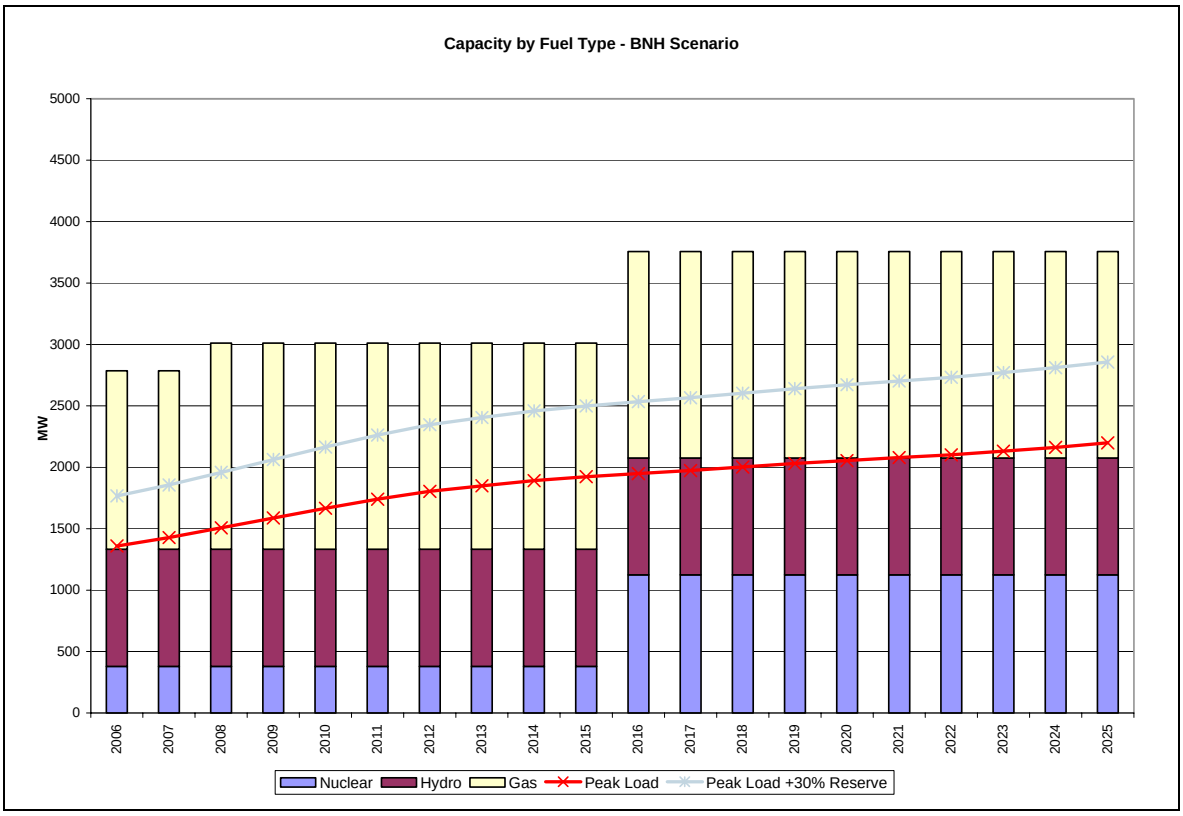


Figure F.2.2. Generation Energy Mix

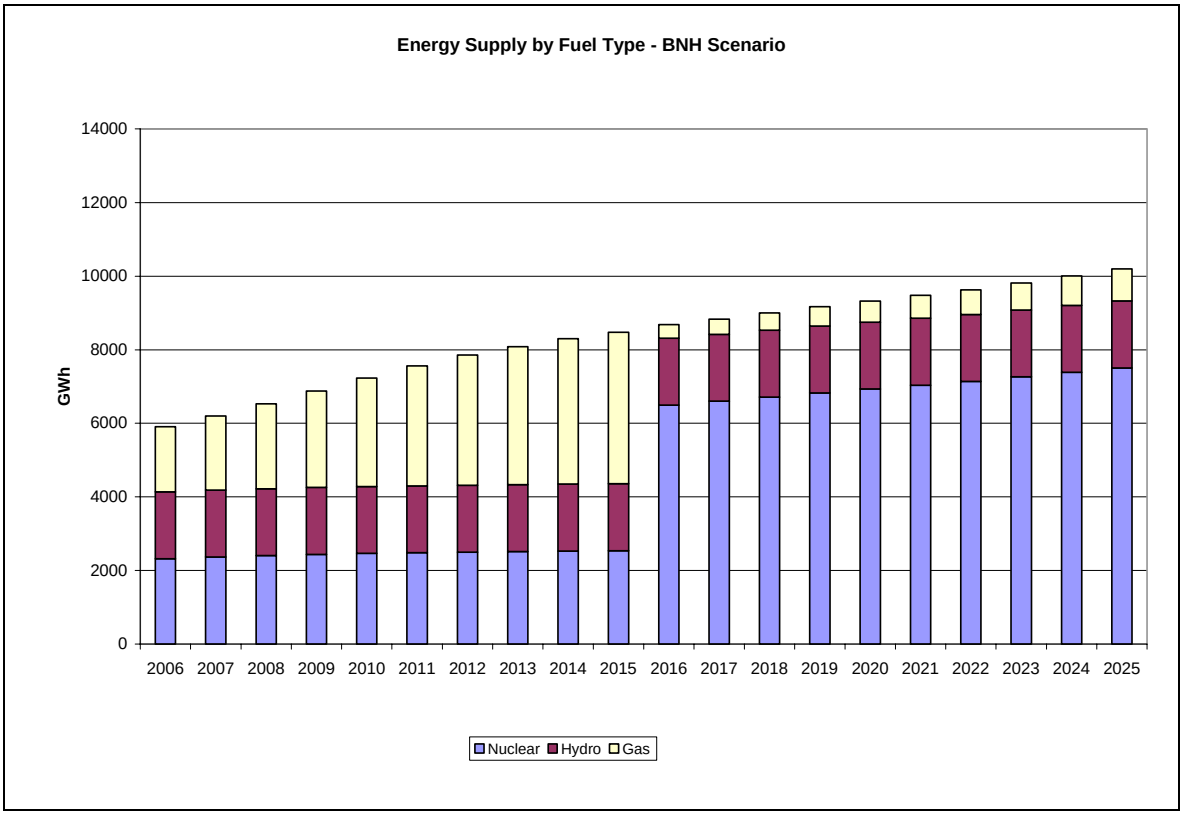
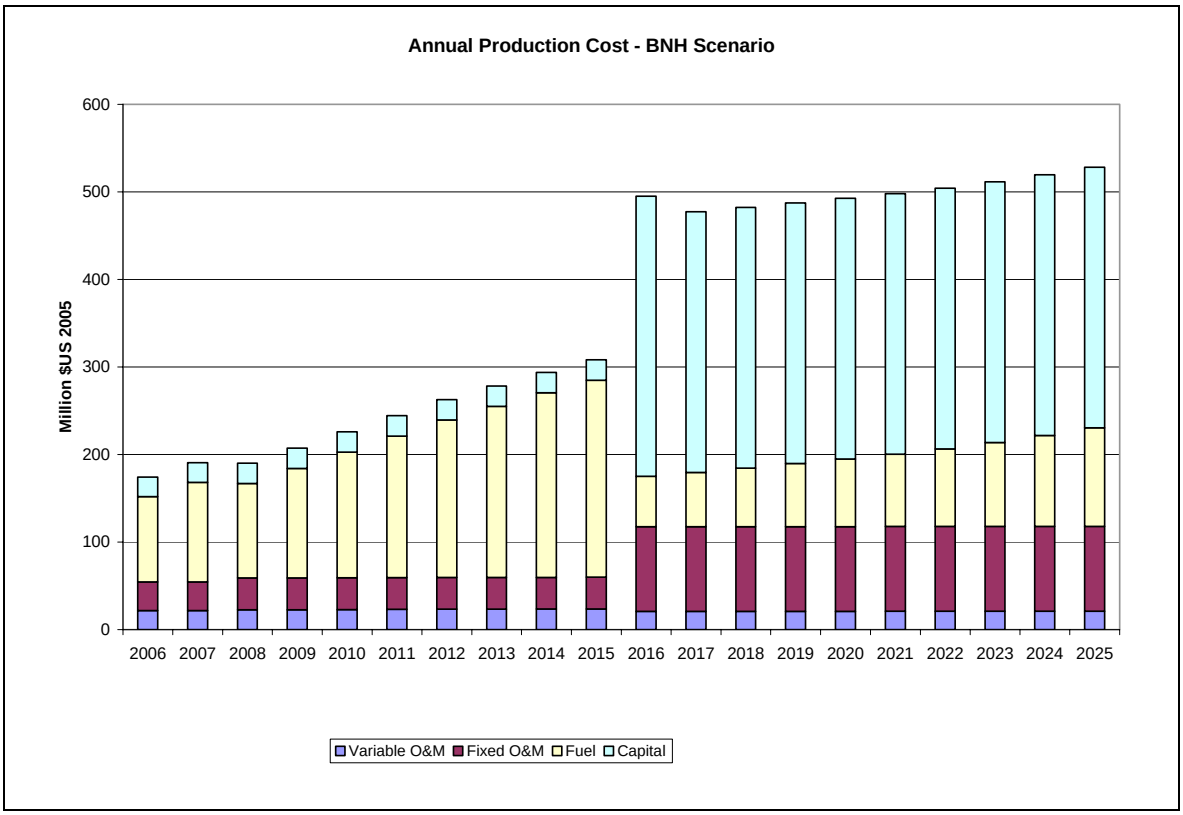


Figure F.2.3. Annual Generation Costs



CASE 3. BNS SCENARIO

Table F.3. Capacity Additions and Retirements for BNS Scenario

Case	Year	2008	2016
BNS	Capacity Addition	Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP16

Figure F.3.1. Generation Capacity Mix

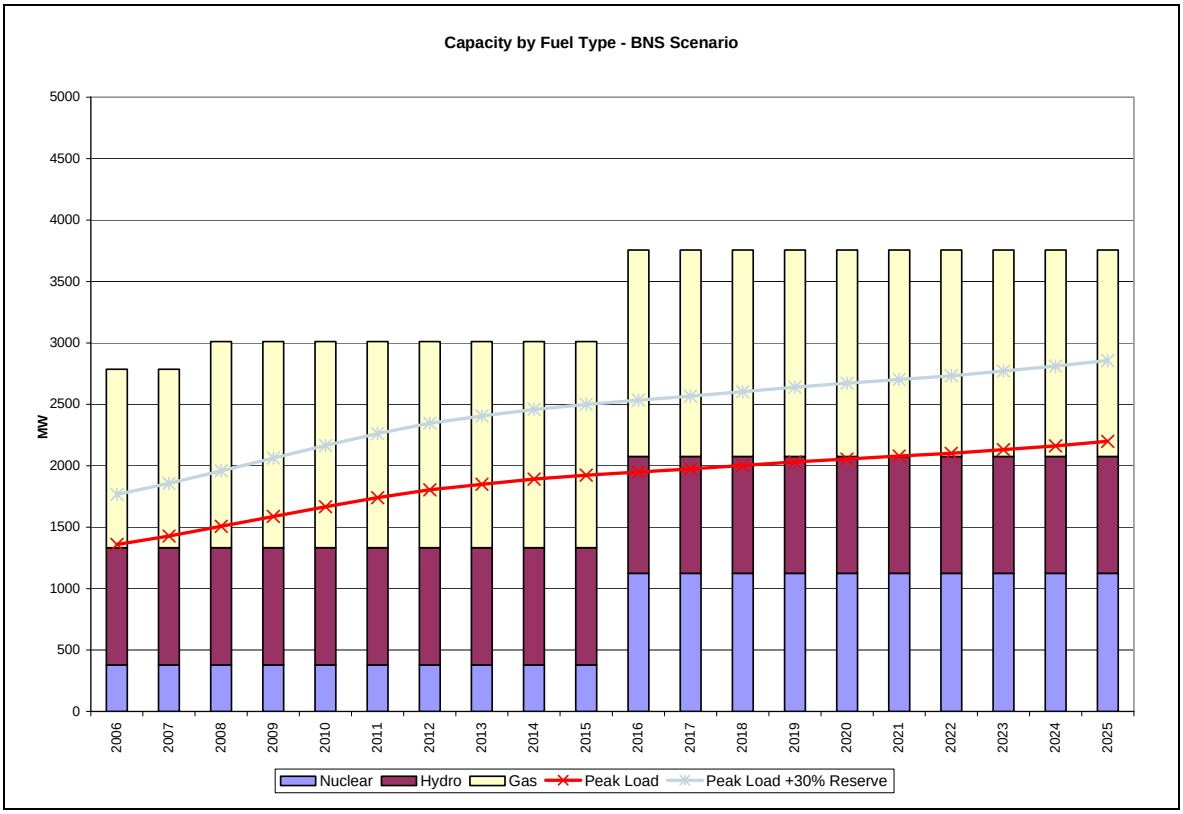


Figure F.3.2. Generation Energy Mix

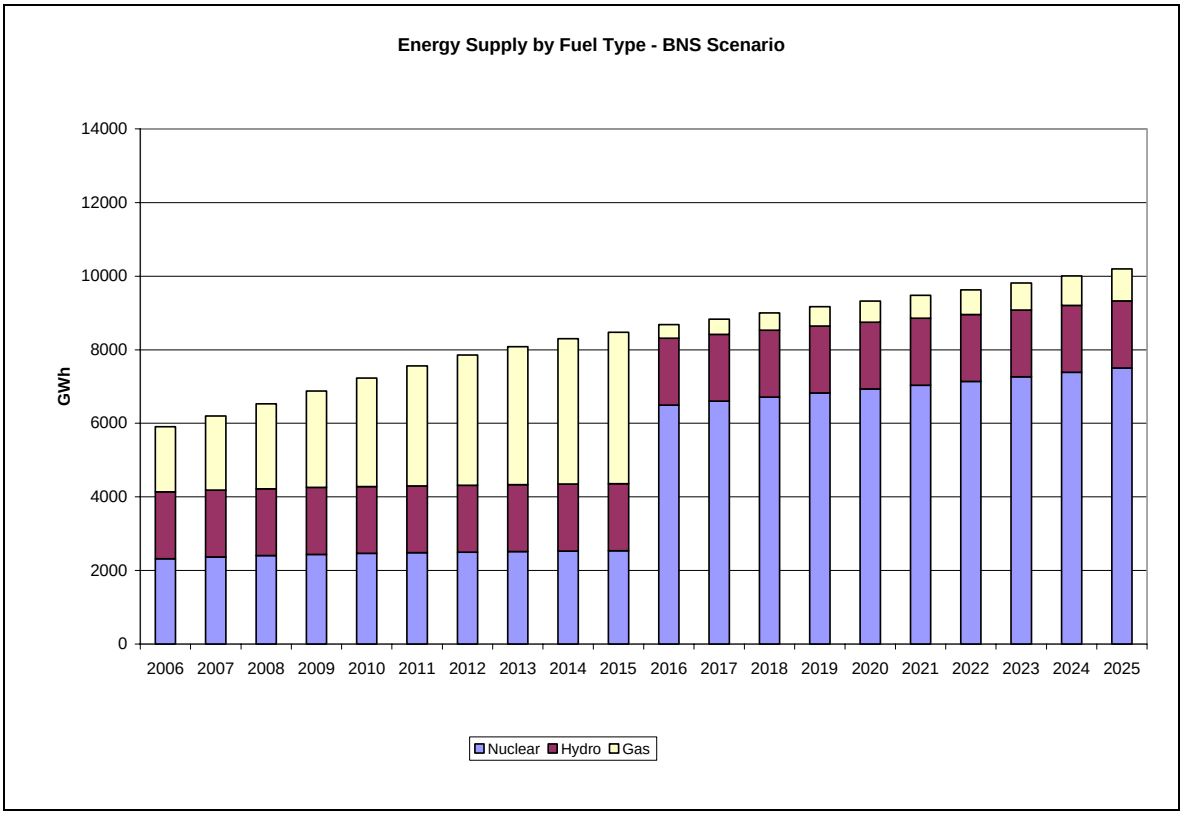
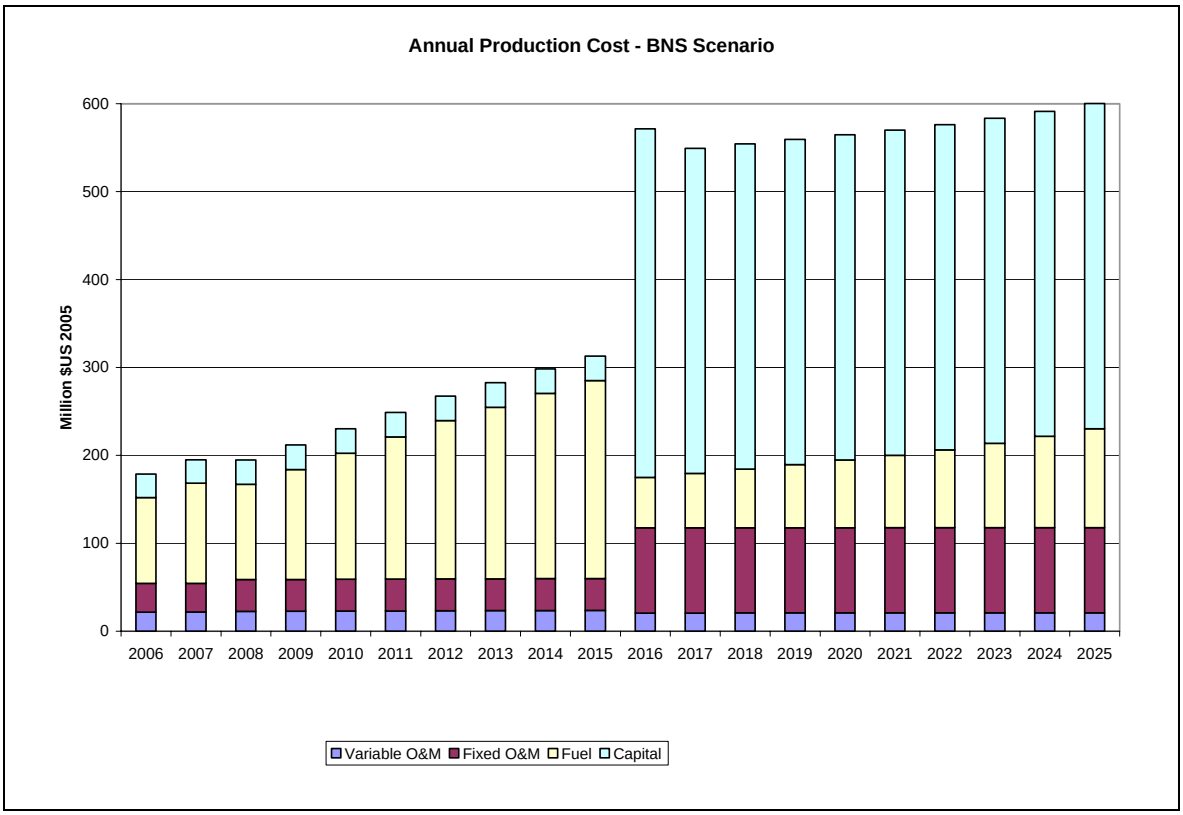


Figure F.3.3. Annual Generation Costs



CASE 4. HNB SCENARIO

Table F.4. Capacity Additions and Retirements for HNB Scenario

Case	Year	2008	2009	2016
HNB	Capacity Addition	Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP16

Figure F.4.1. Generation Capacity Mix

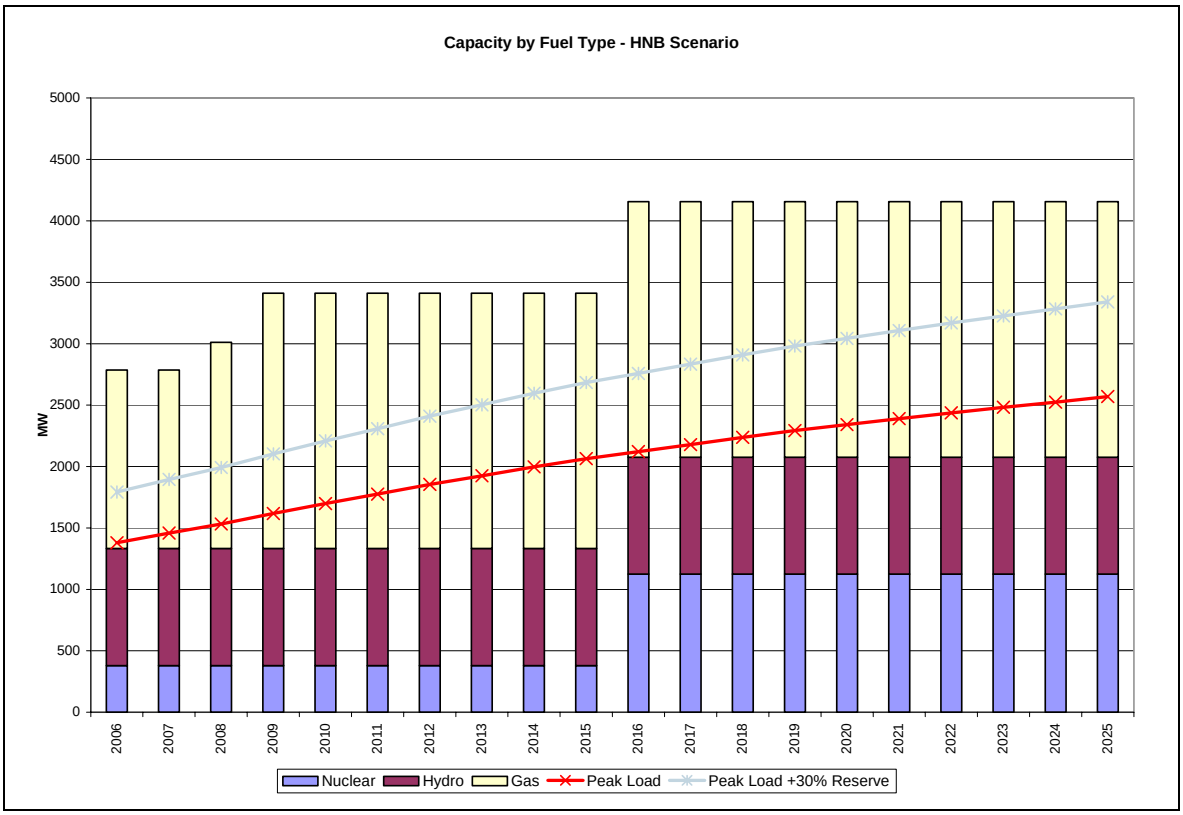


Figure F.4.2. Generation Energy Mix

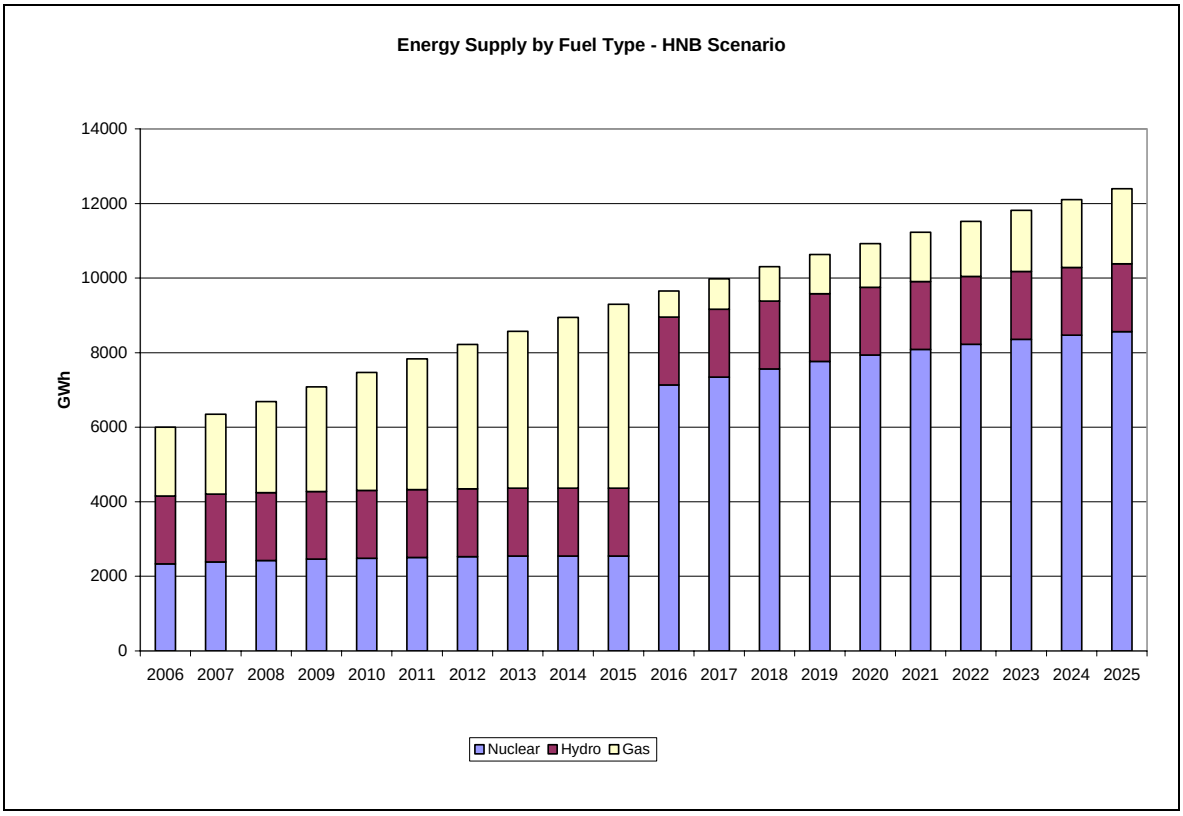
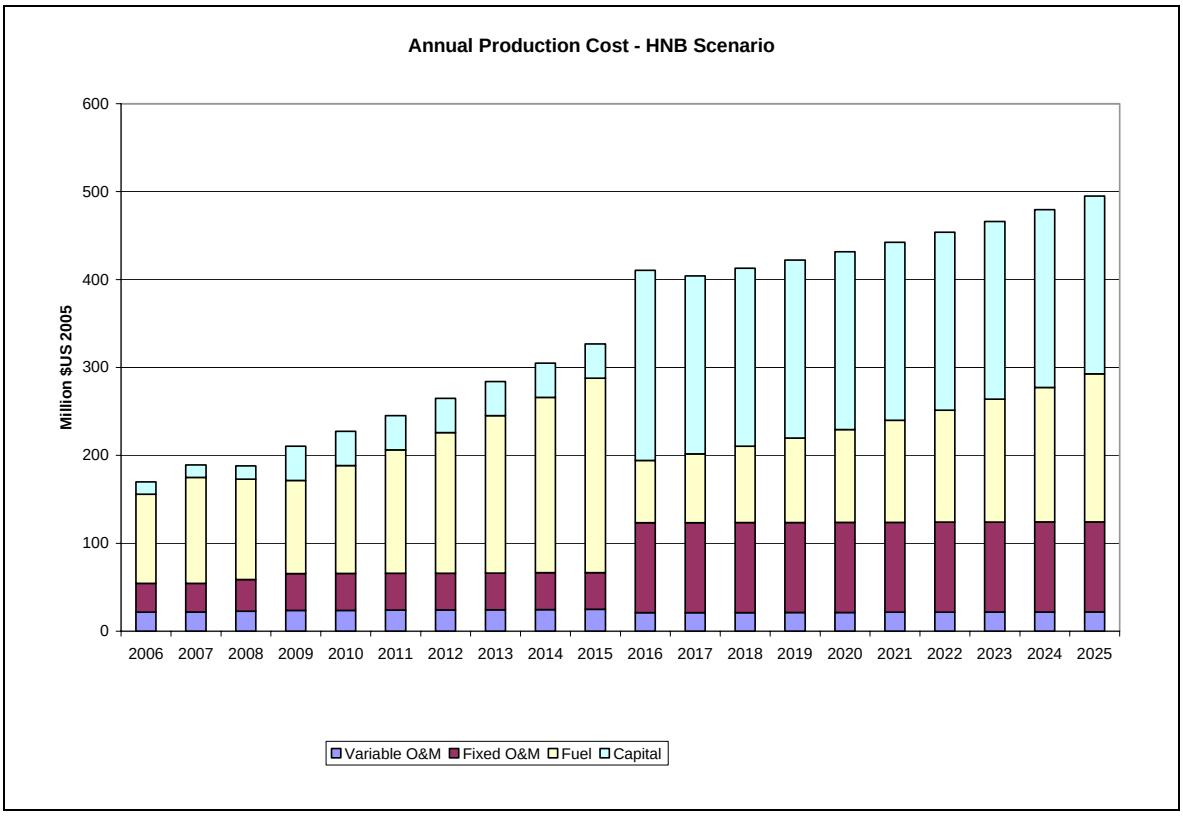


Figure F.4.3. Annual Generation Costs



CASE 5. HNH SCENARIO

Table F.5. Capacity Additions and Retirements for HNH Scenario

Case	Year	2008	2011	2016
HNH	Capacity Addition	Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP16

Figure F.5.1. Generation Capacity Mix

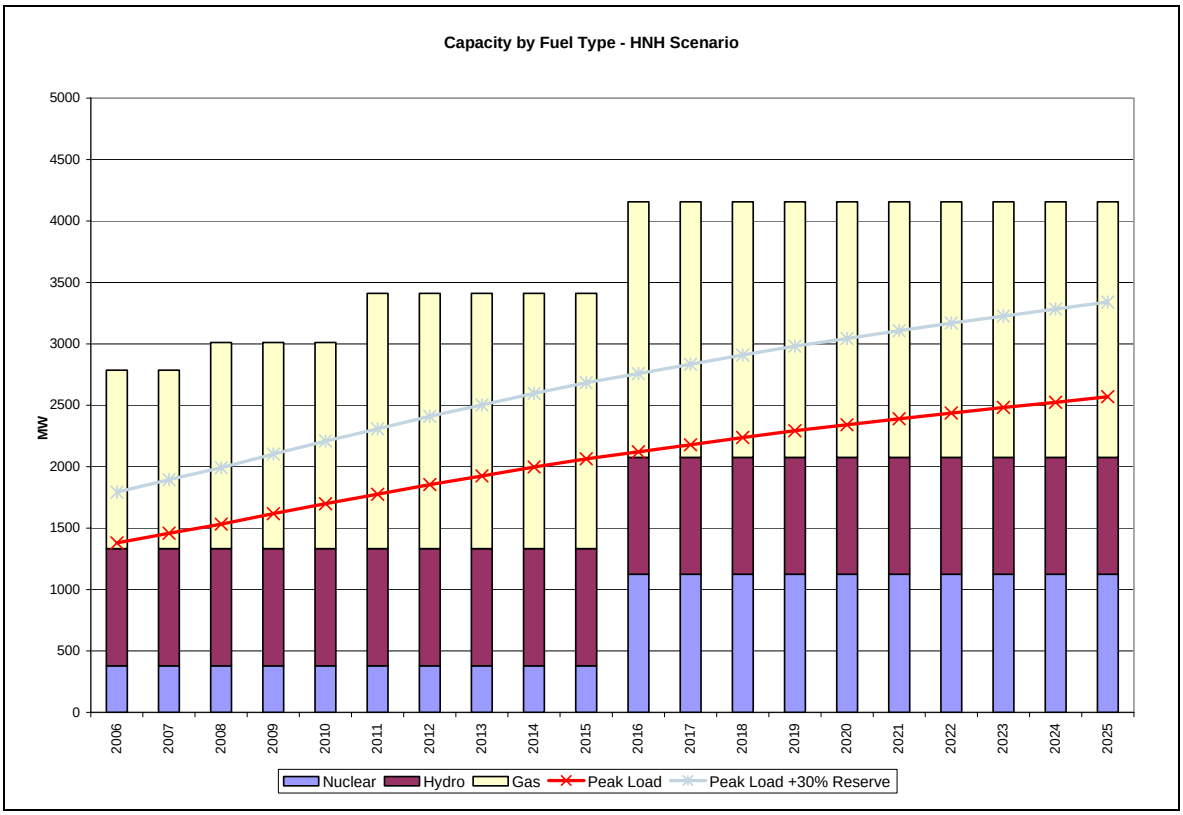


Figure F.5.2. Generation Energy Mix

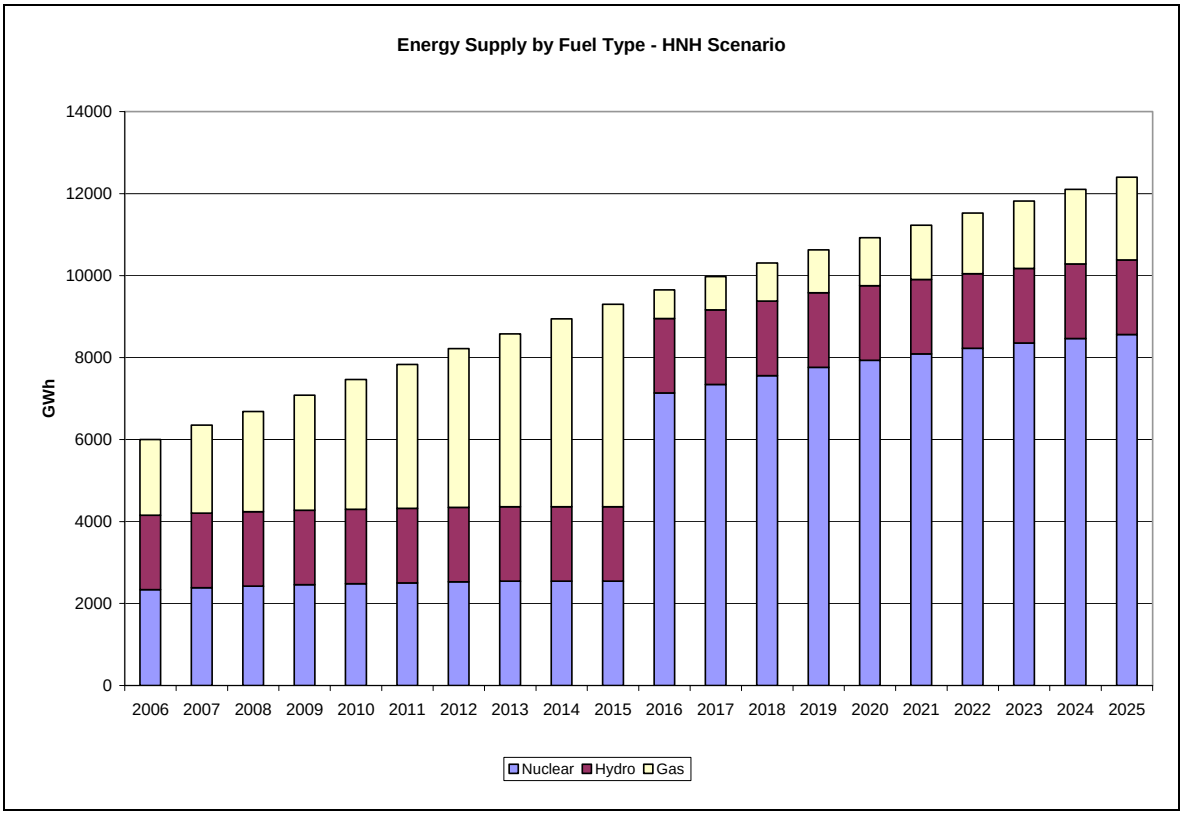
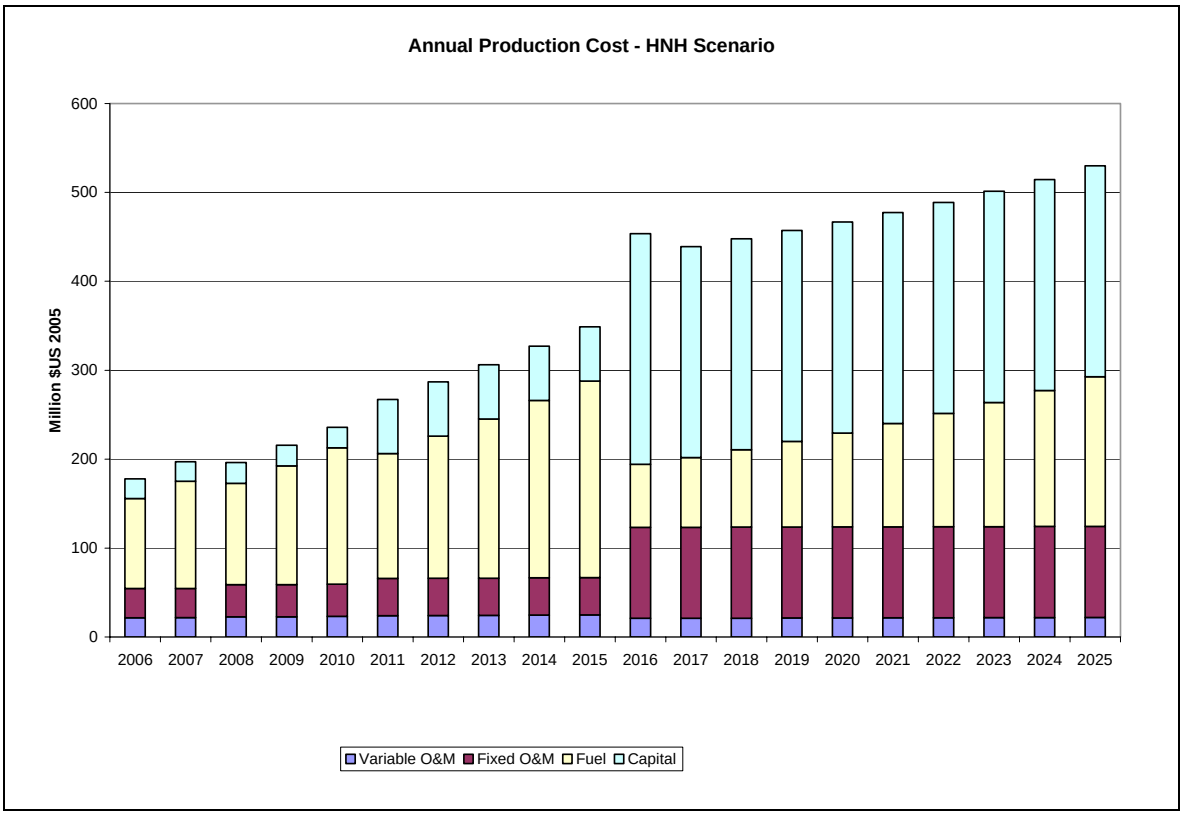


Figure F.5.3. Annual Generation Costs



CASE 6. LNB SCENARIO

Table F.6. Capacity Additions and Retirements for LNB Scenario

Case	Year	2008	2016
LNB	Capacity Addition	Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP16

Figure F.6.1. Generation Capacity Mix

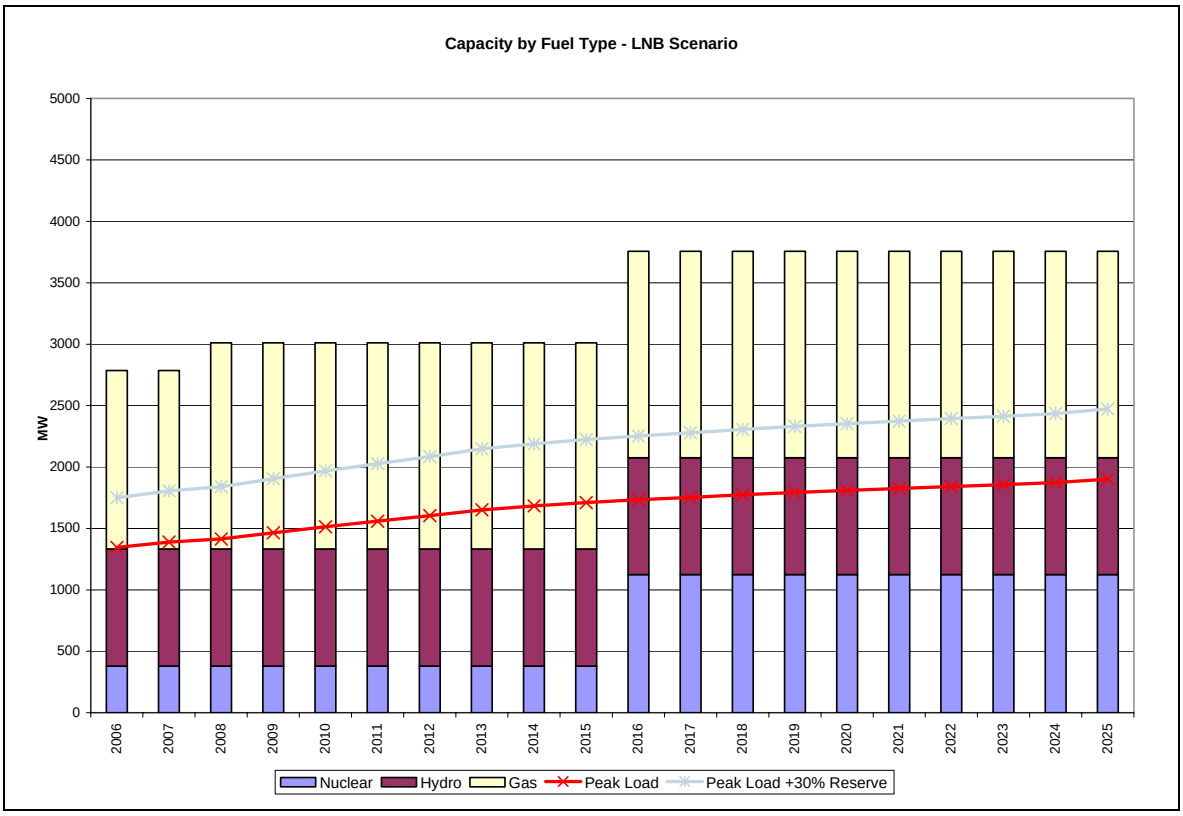


Figure F.6.2. Generation Energy Mix

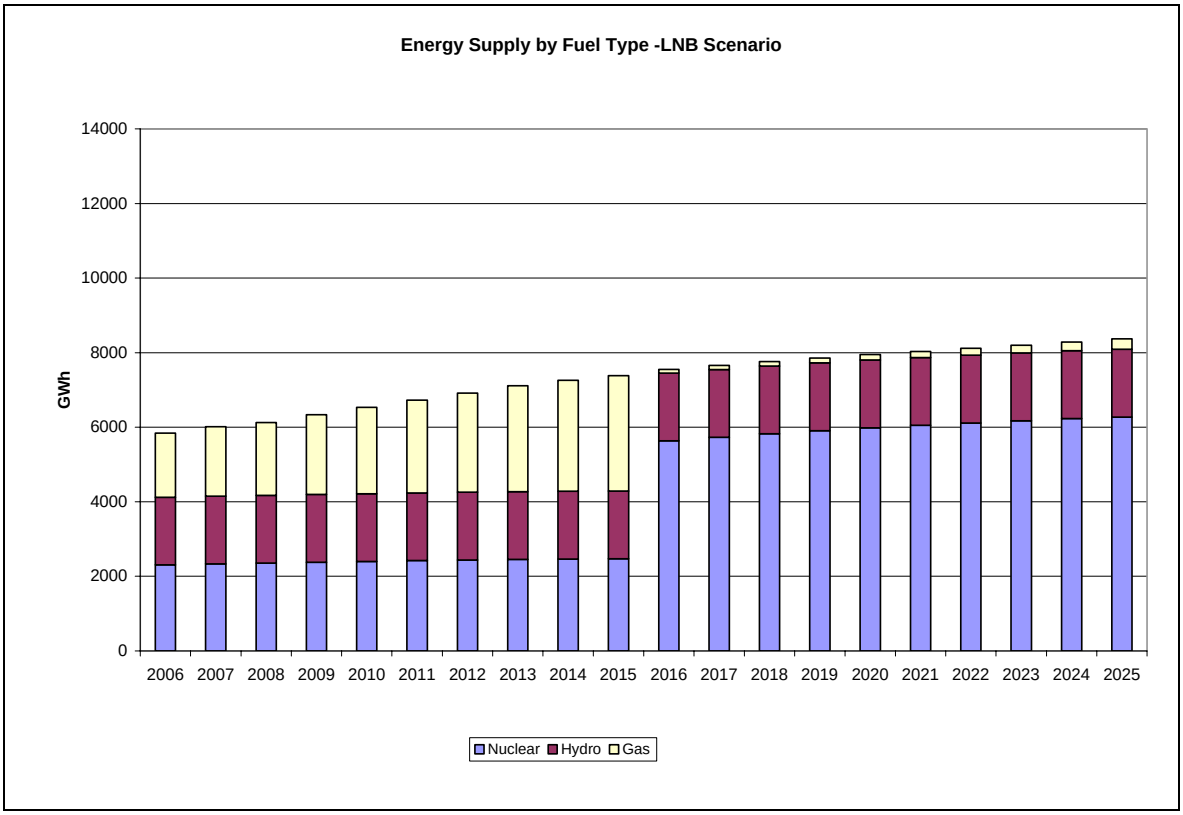
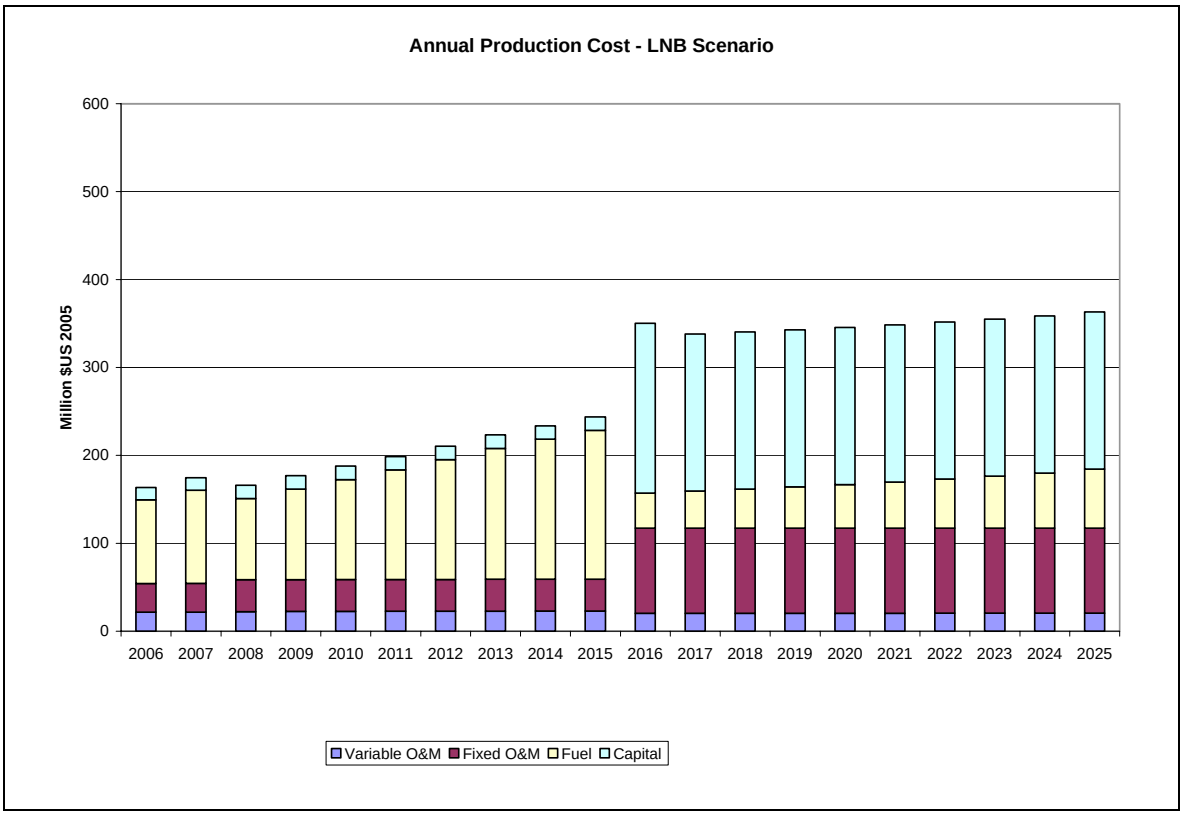


Figure F.6.3. Annual Generation Costs



CASE 7. LNH SCENARIO

Table F.7. Capacity Additions and Retirements for LNH Scenario

Case	Year	2008	2016
LNH	Capacity Addition	Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP16

Figure F 7.1. Generation Capacity Mix

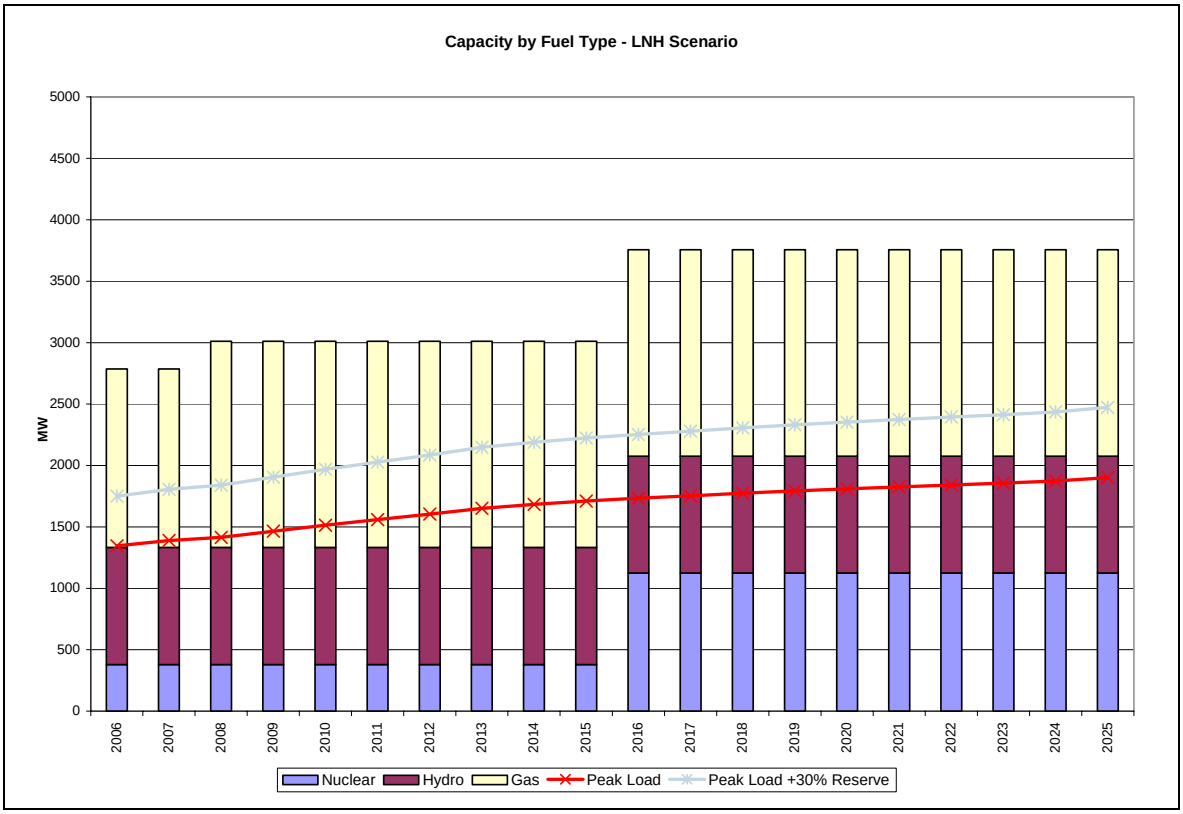


Figure F 7.2. Generation Energy Mix

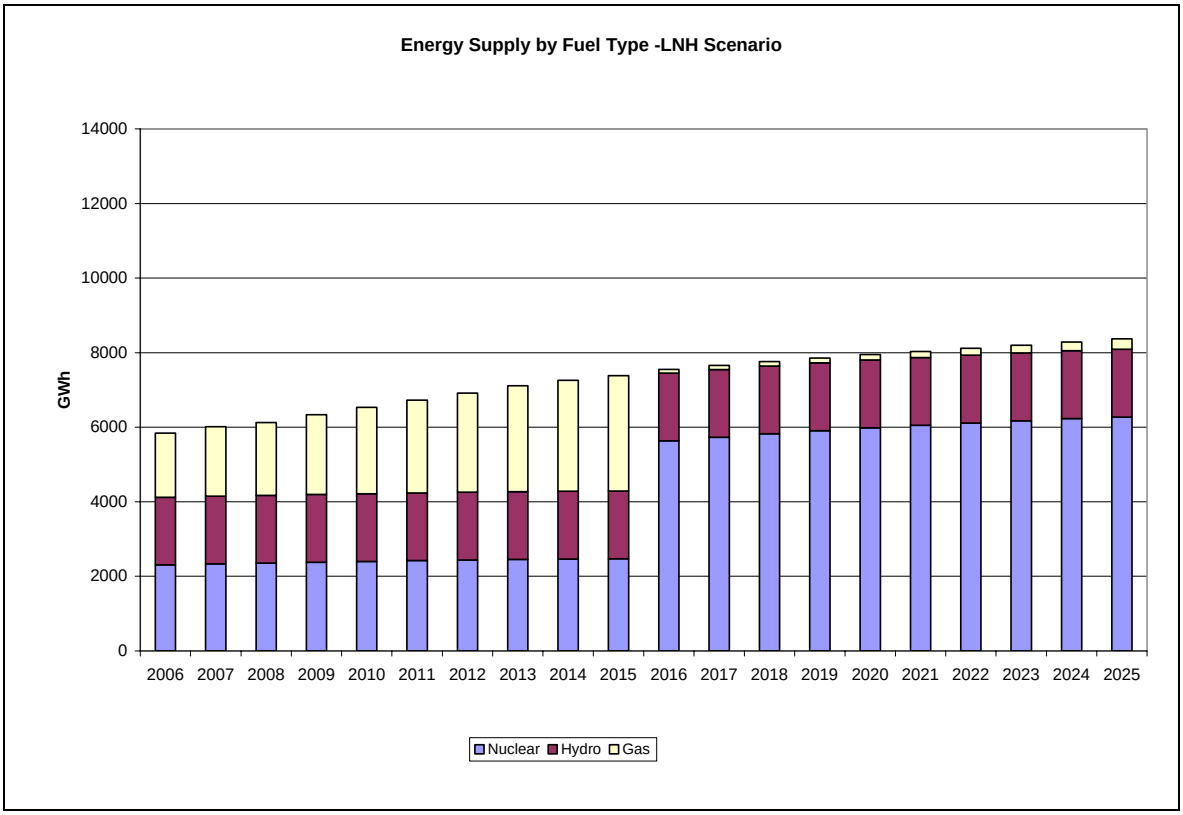
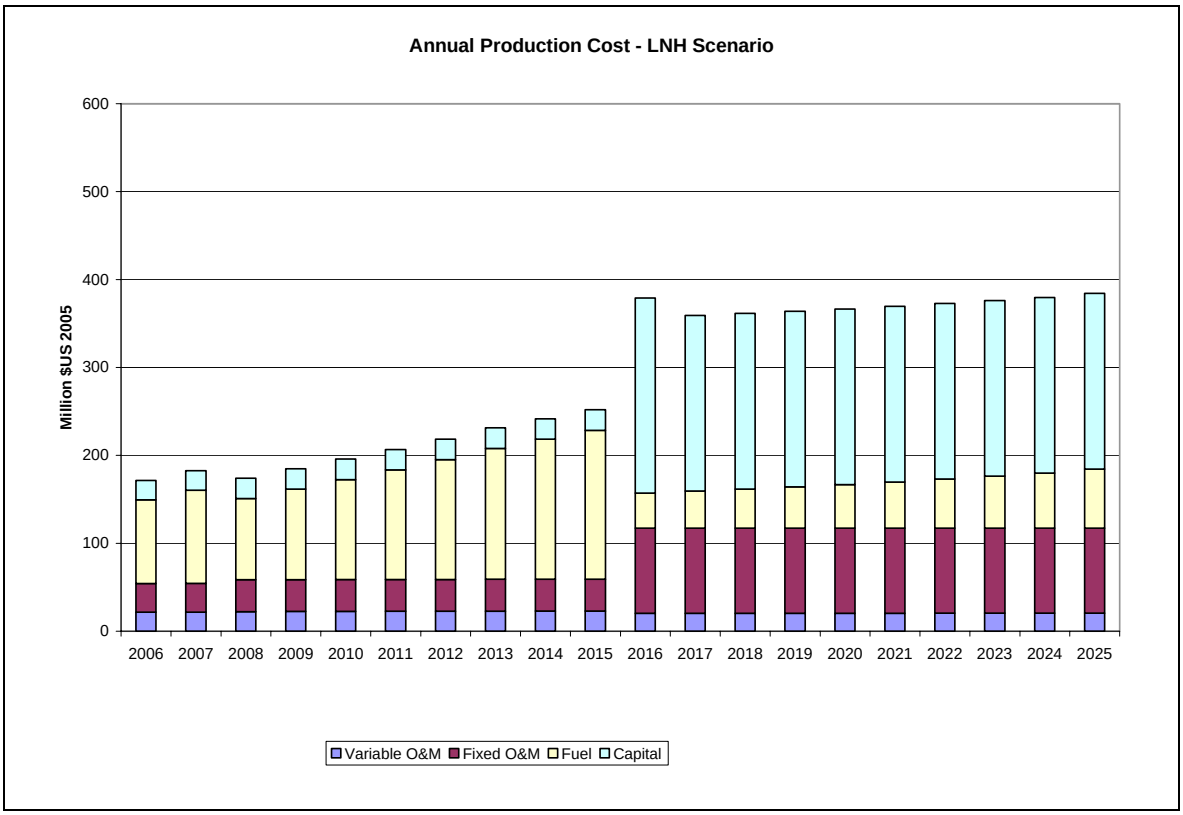


Figure F 7.3. Annual Generation Costs



CASE 8. NO_NUCE SCENARIO

Table F.8. Capacity Additions and Retirements for No_Nuce Scenario

Case	Year	2008	2009	2016	2018
No_Nuce	Capacity Addition	Yerevan JBIC	400MW CCGT	225 MW CCGT	225MW CCGT
	Capacity Retirement			ANPP16	

Figure F.8.1. Generation Capacity Mix

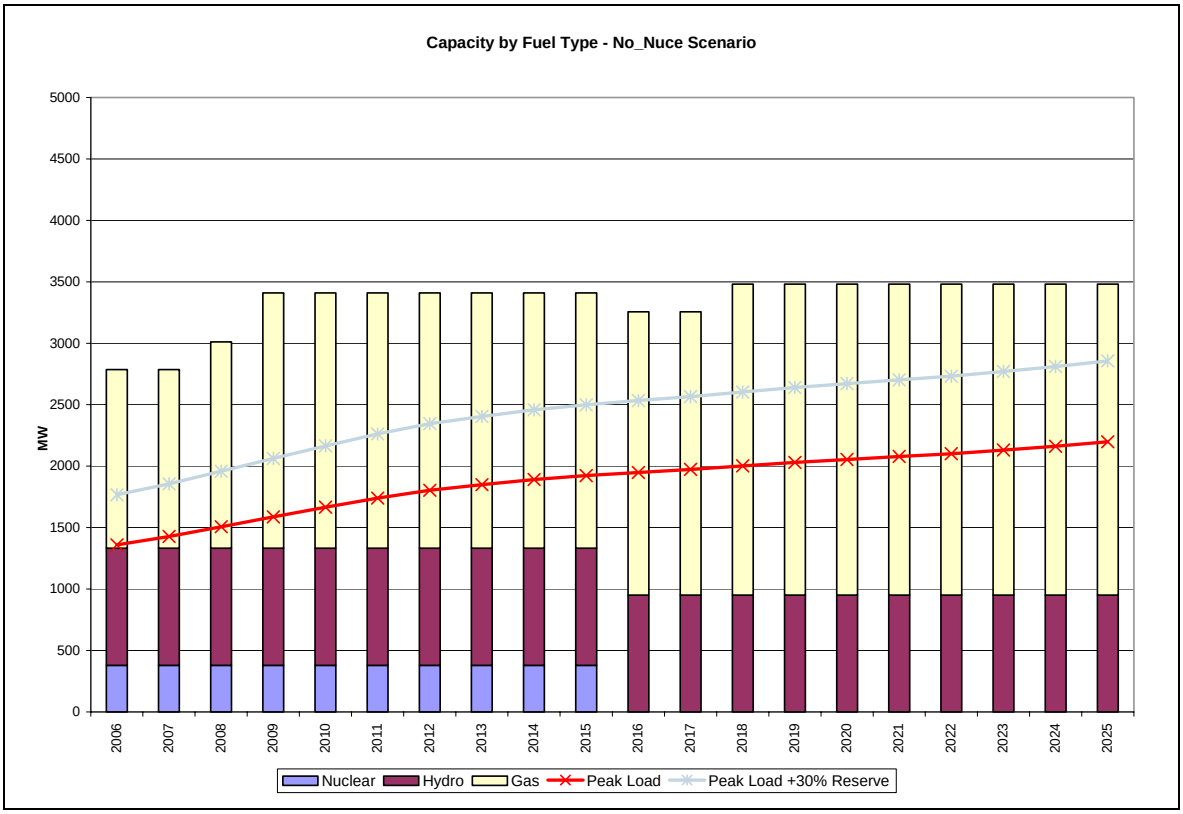


Figure F.8.2. Generation Energy Mix

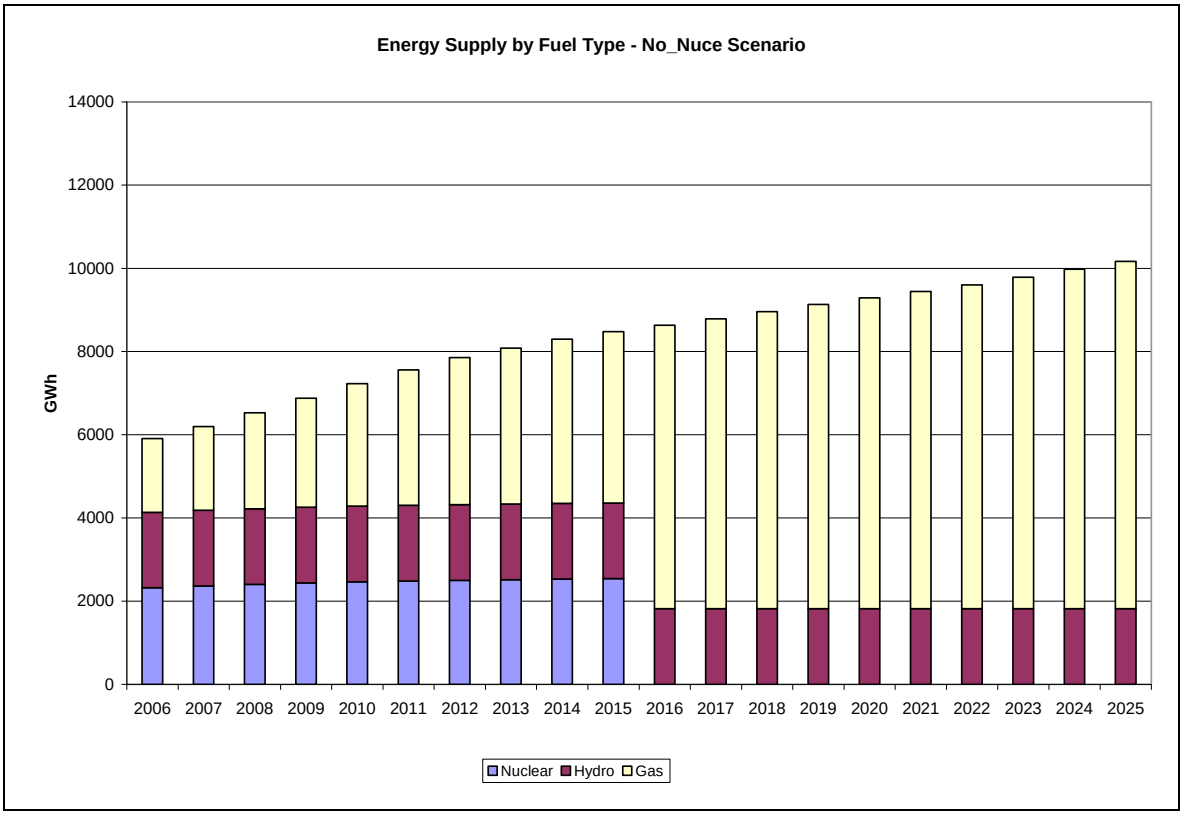
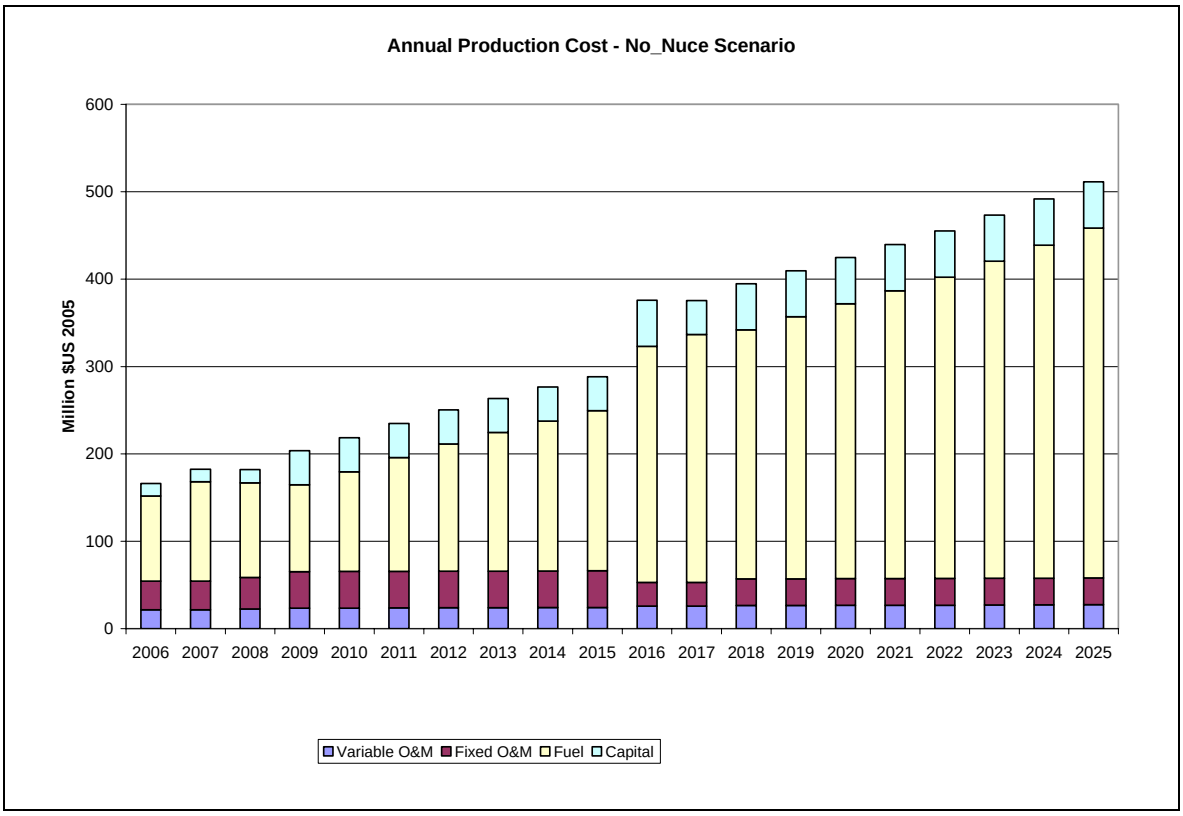


Figure F.8.3. Annual Generation Costs



CASE 9. BNB_NT SCENARIO

Table F.9. Capacity Additions and Retirements for BNB_NT Scenario

Case	Year	2008	2016
BNB_NT	Capacity Addition	Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP16

Figure F.9.1. Generation Capacity Mix

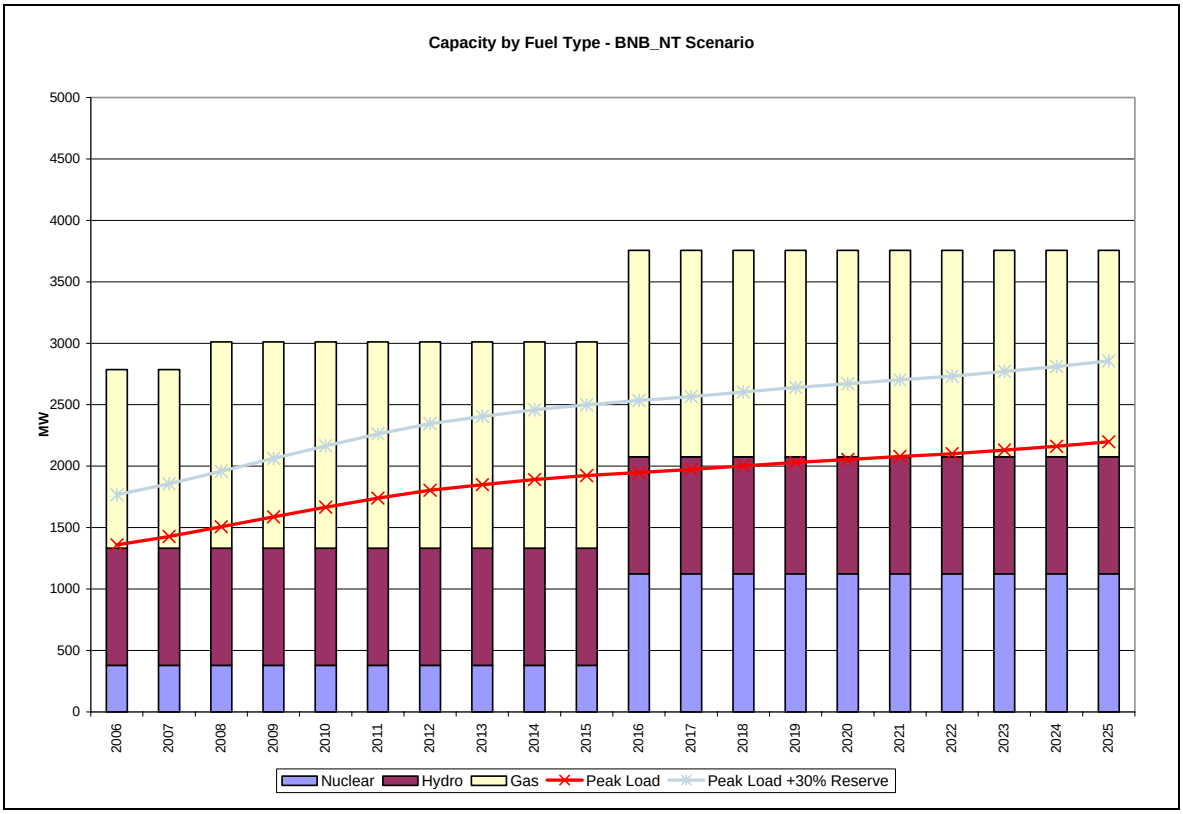


Figure F.9.2. Generation Energy Mix

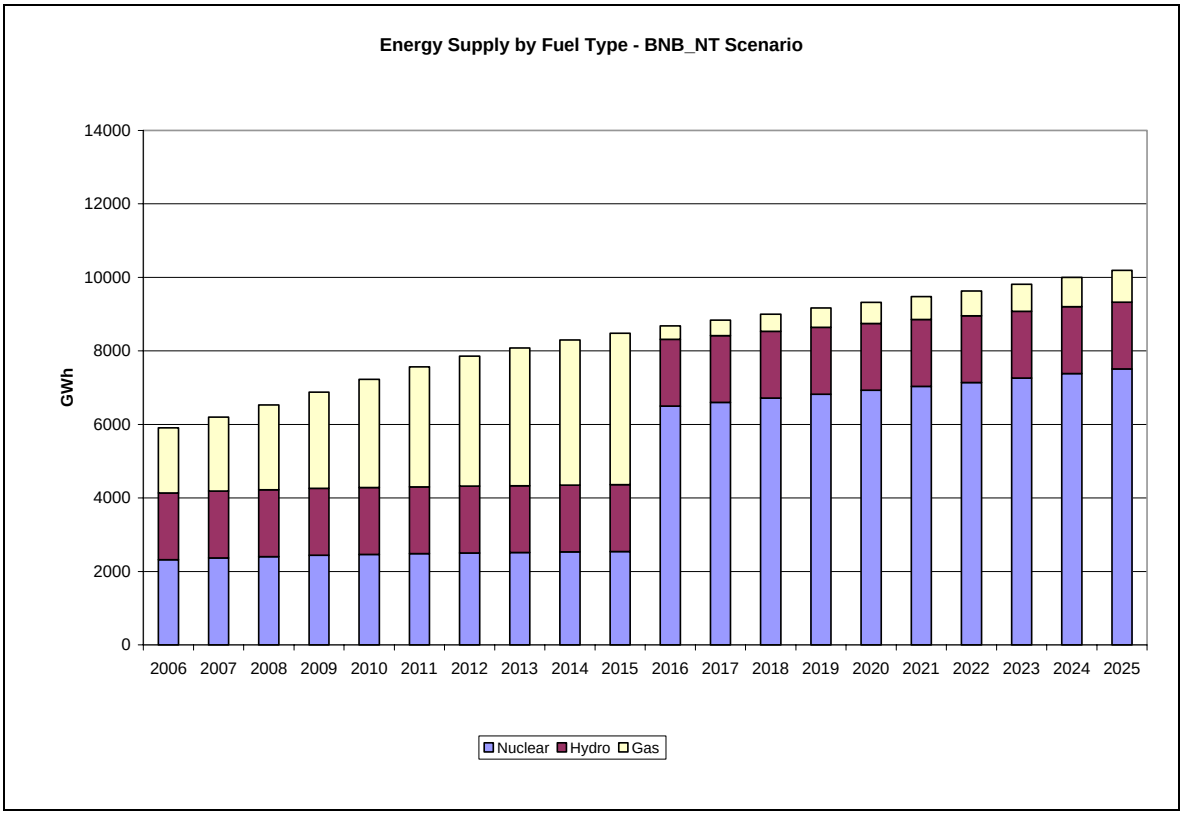
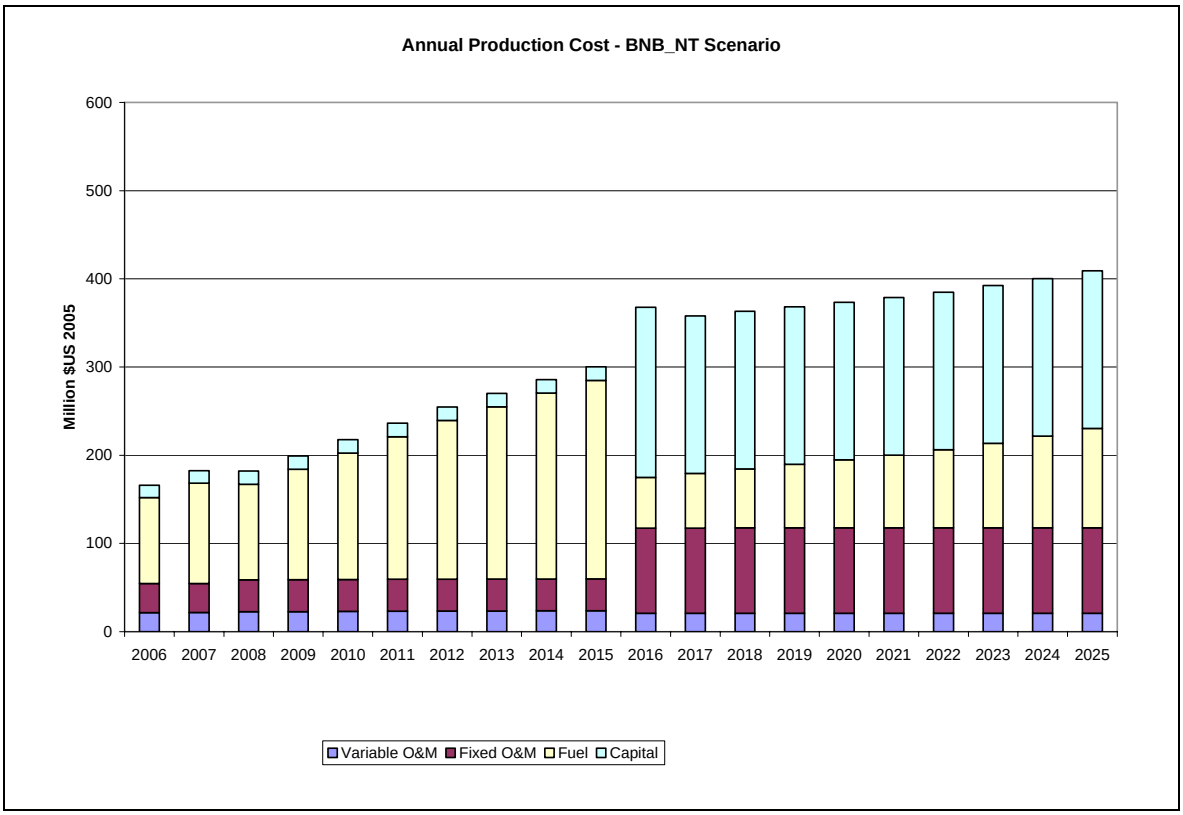


Figure F.9.3. Annual Generation Costs



CASE 10. TR SCENARIO

Table F.10. Capacity Additions and Retirements for TR Scenario

Case	Year	2006	2008	2009	2016	2019
TR	Capacity Addition		Yerevan JBIC	400MW CCGT	ACR 1000	
	Capacity Retirement	Yerevan 1,2,4			Hrazdan existing; ANPP16	Yerevan 6,7

Figure F.10.1. Generation Capacity by Fuel Type

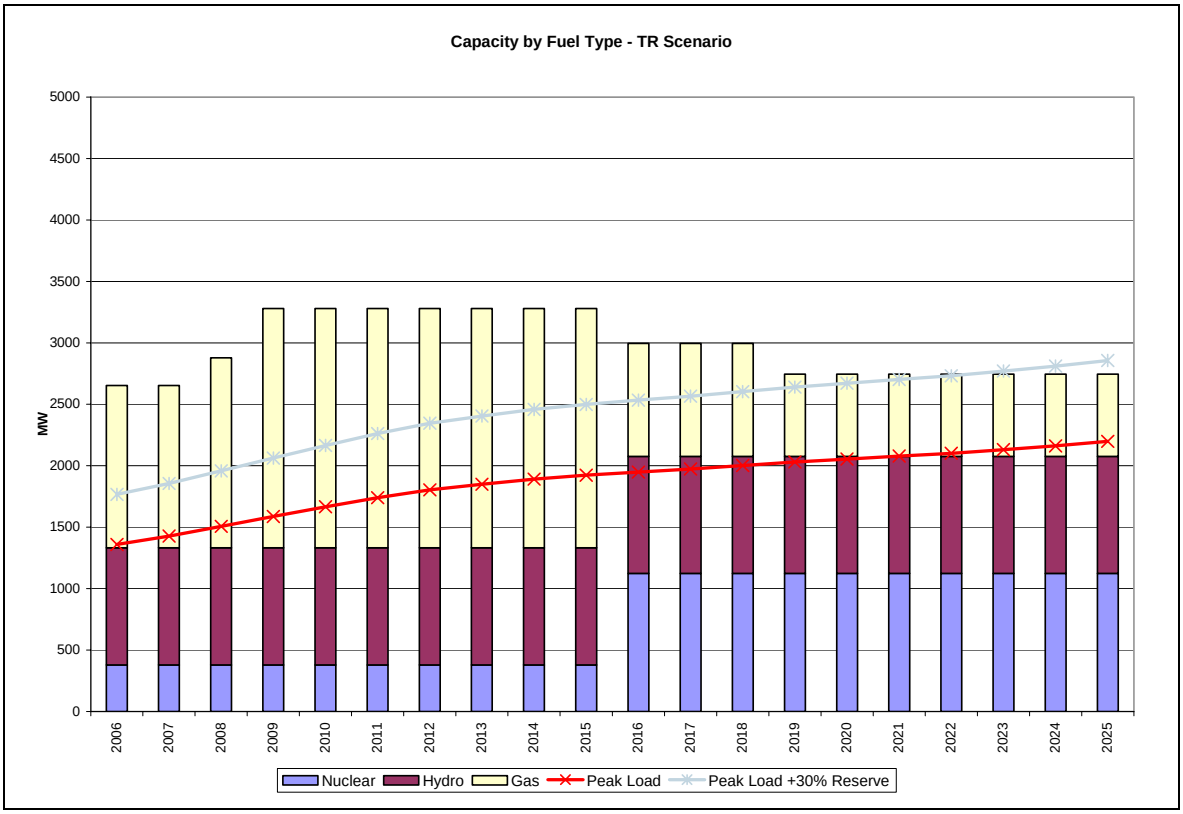


Figure F.10.2. Generation Energy Supply

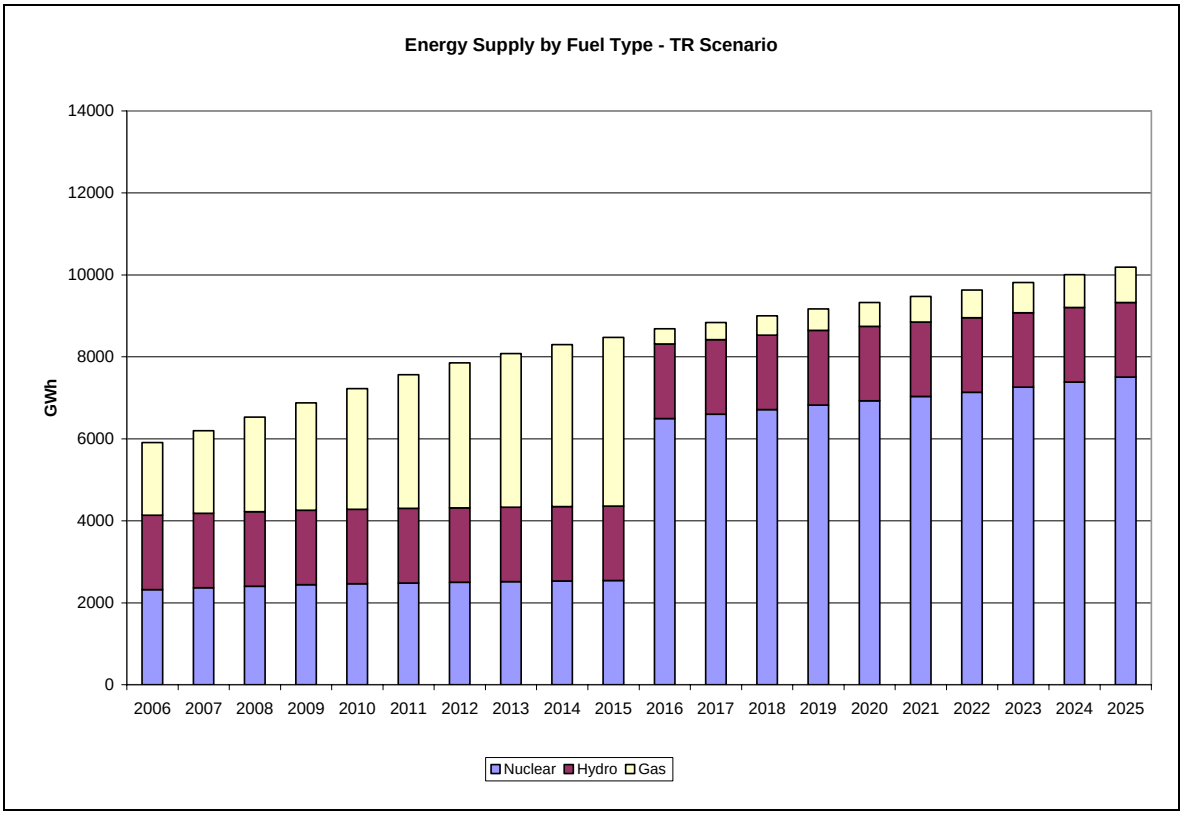
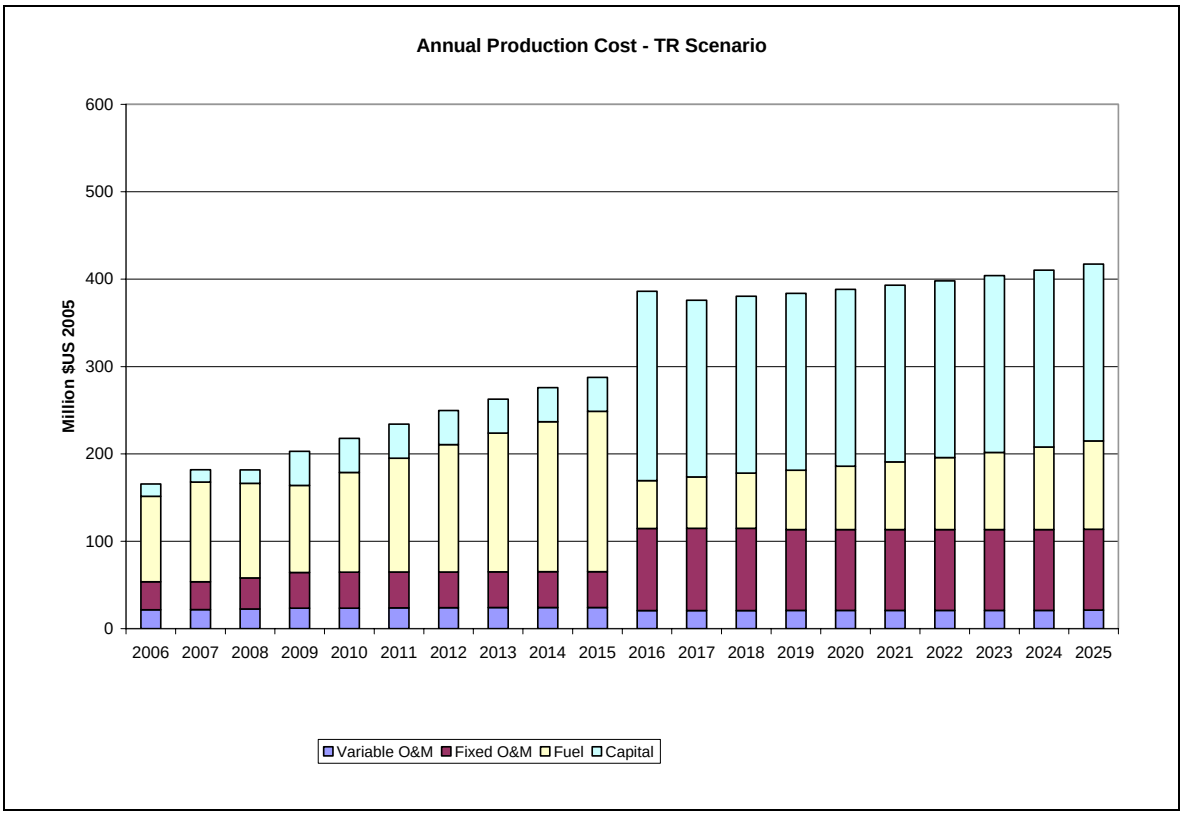


Figure F.10.3. Annual Generation Costs



CASE 11. YC SCENARIO

Table F.11. Capacity Additions and Retirements for YC Scenario

Case	Year	2009	2016
YC	Capacity Addition	400MW CCGT	ACR 1000
	Capacity Retirement		ANPP16

Figure F.11.1. Generation Capacity by Fuel Type

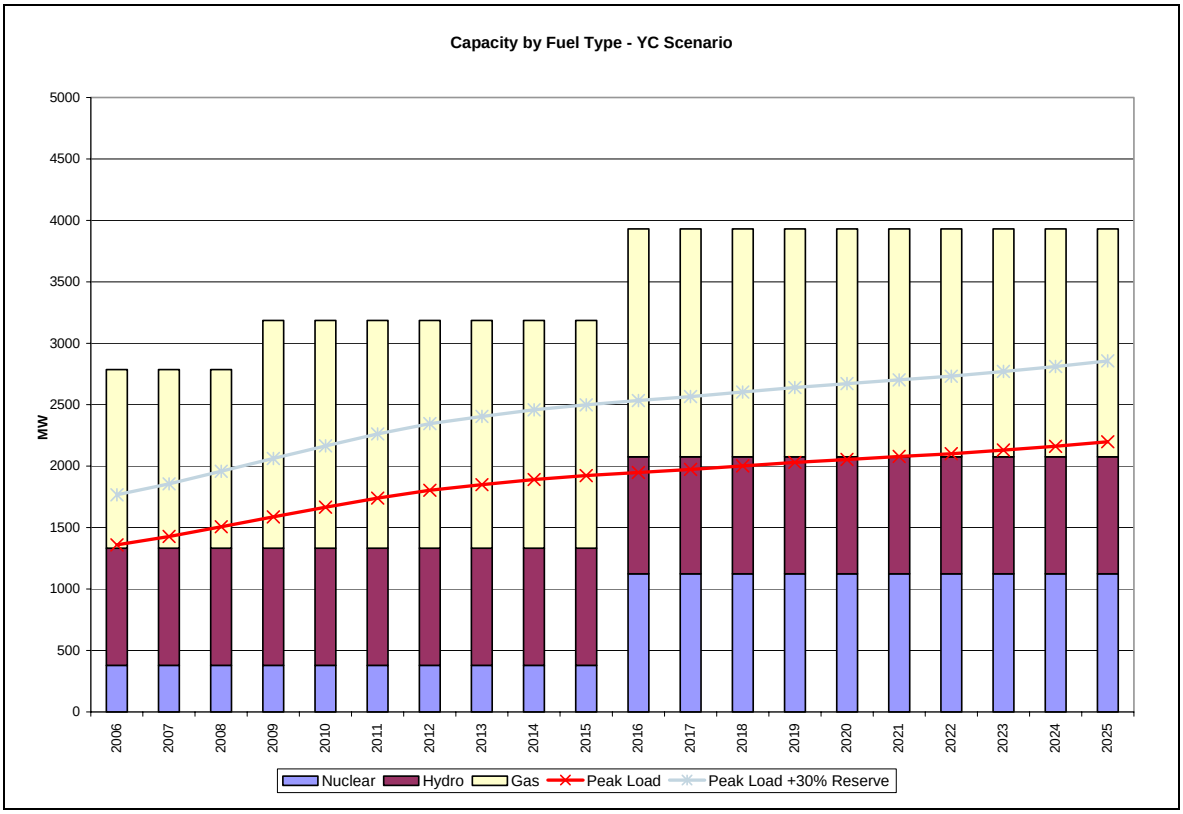


Figure F.11.2. Generation Energy Supply

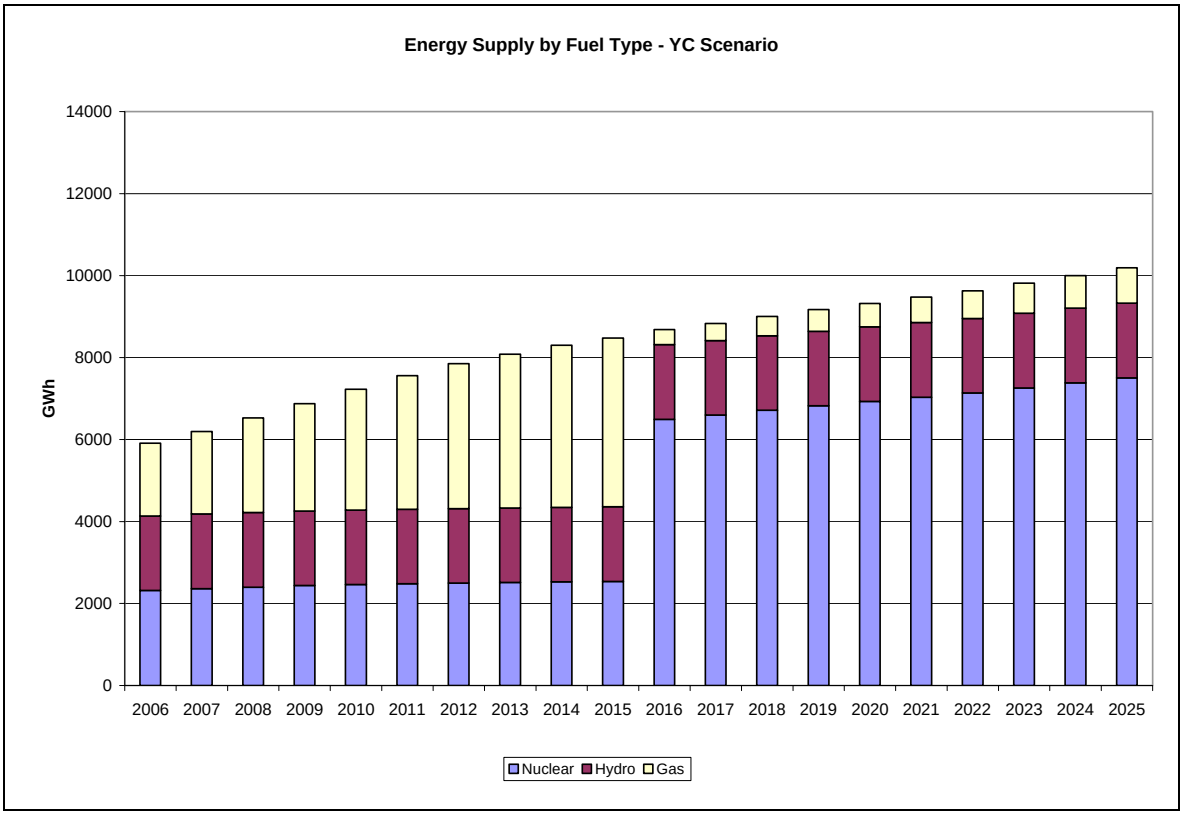
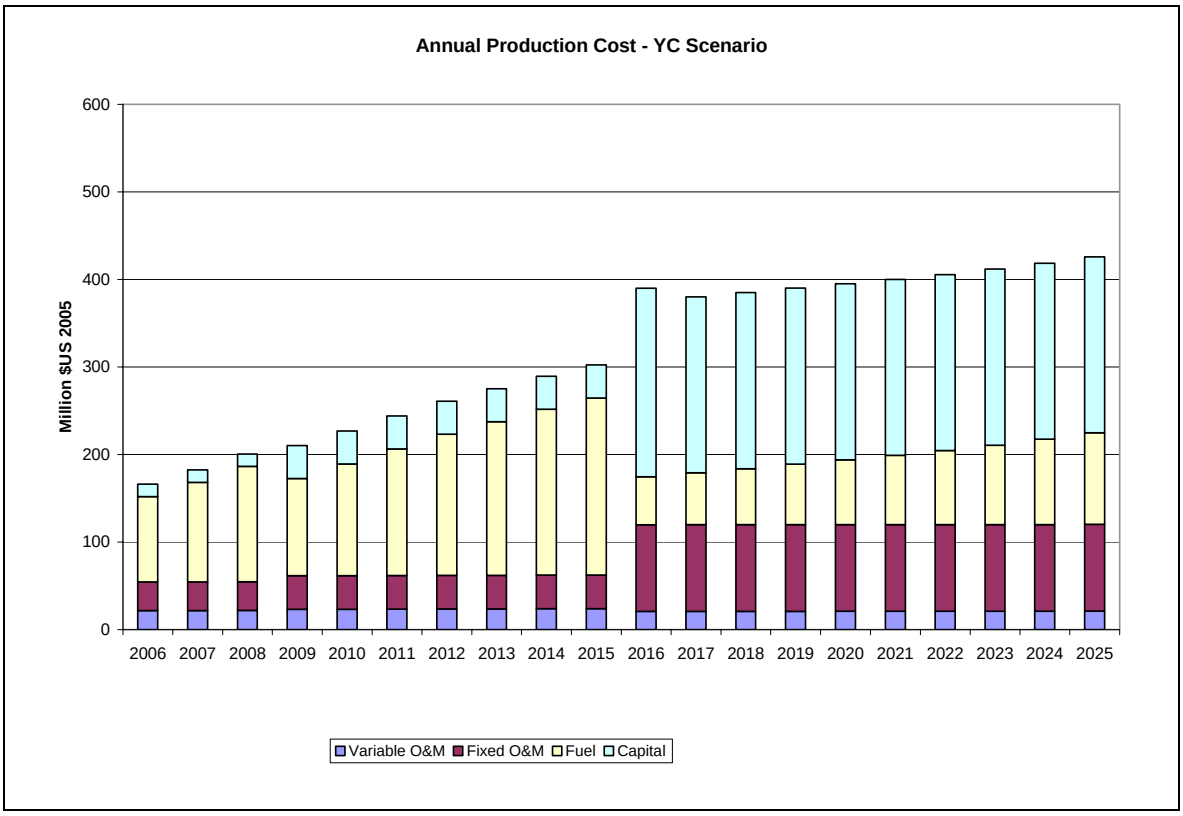


Figure F.11.3. Annual Generation Costs



CASE 12. 25% SCENARIO

Table F.12. Capacity Additions and Retirements for 25% Scenario

Case	Year	2008	2016
25%	Capacity Addition	Yerevan JBIC	ACR 1000
	Capacity Retirement		ANPP16

Figure F.12.1. Generation Capacity by Fuel Type

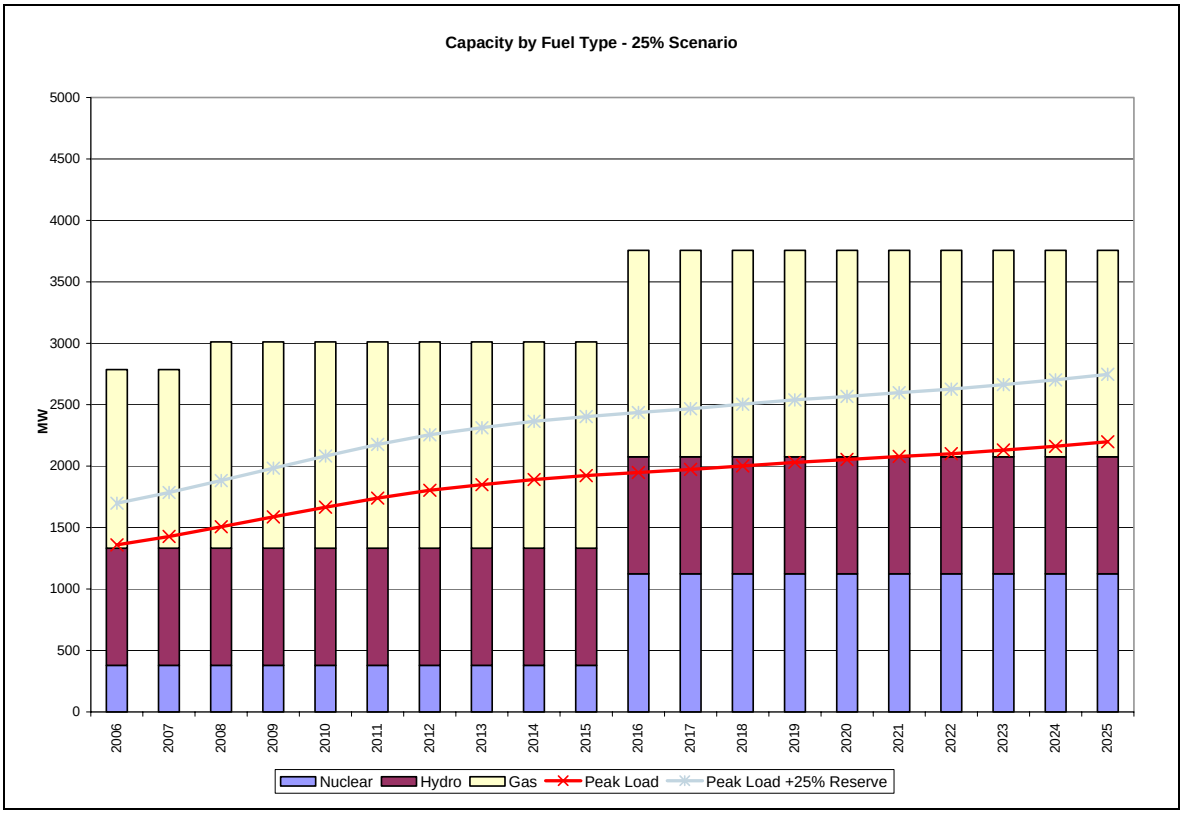


Figure F.12.2. Generation Energy Supply

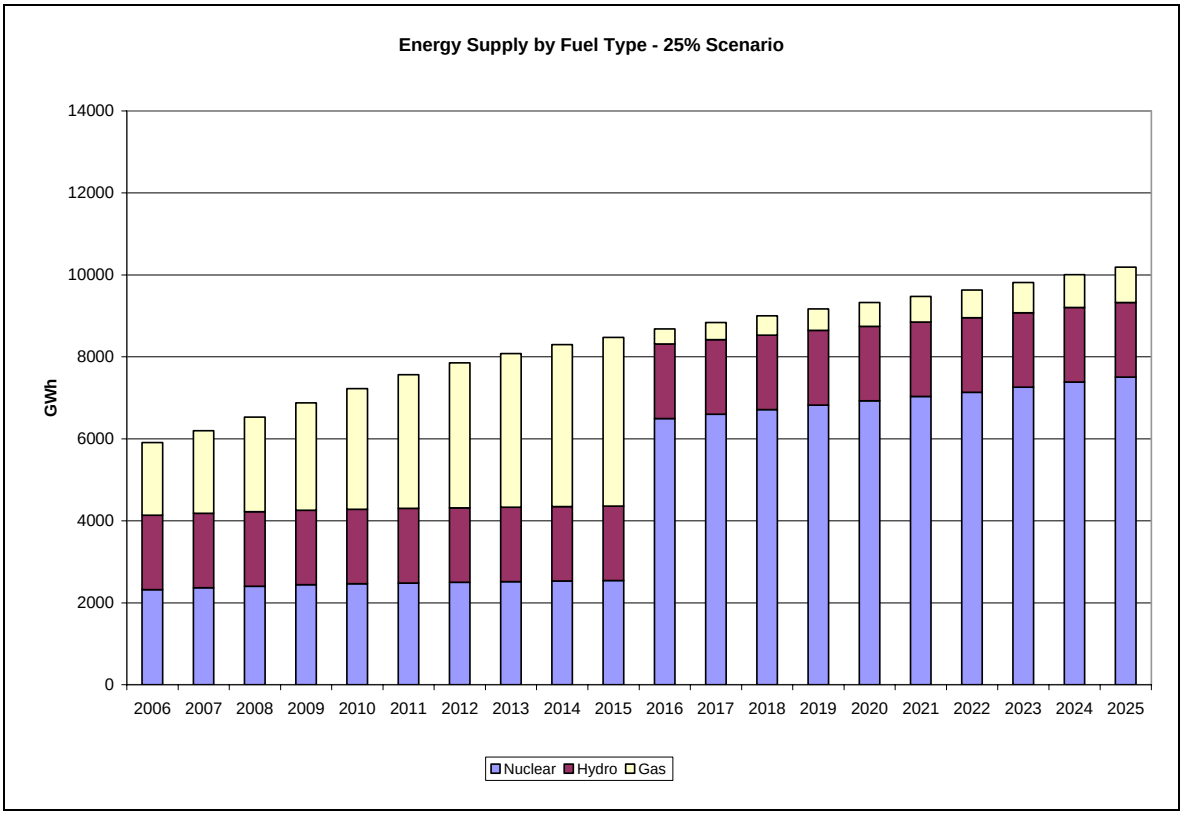
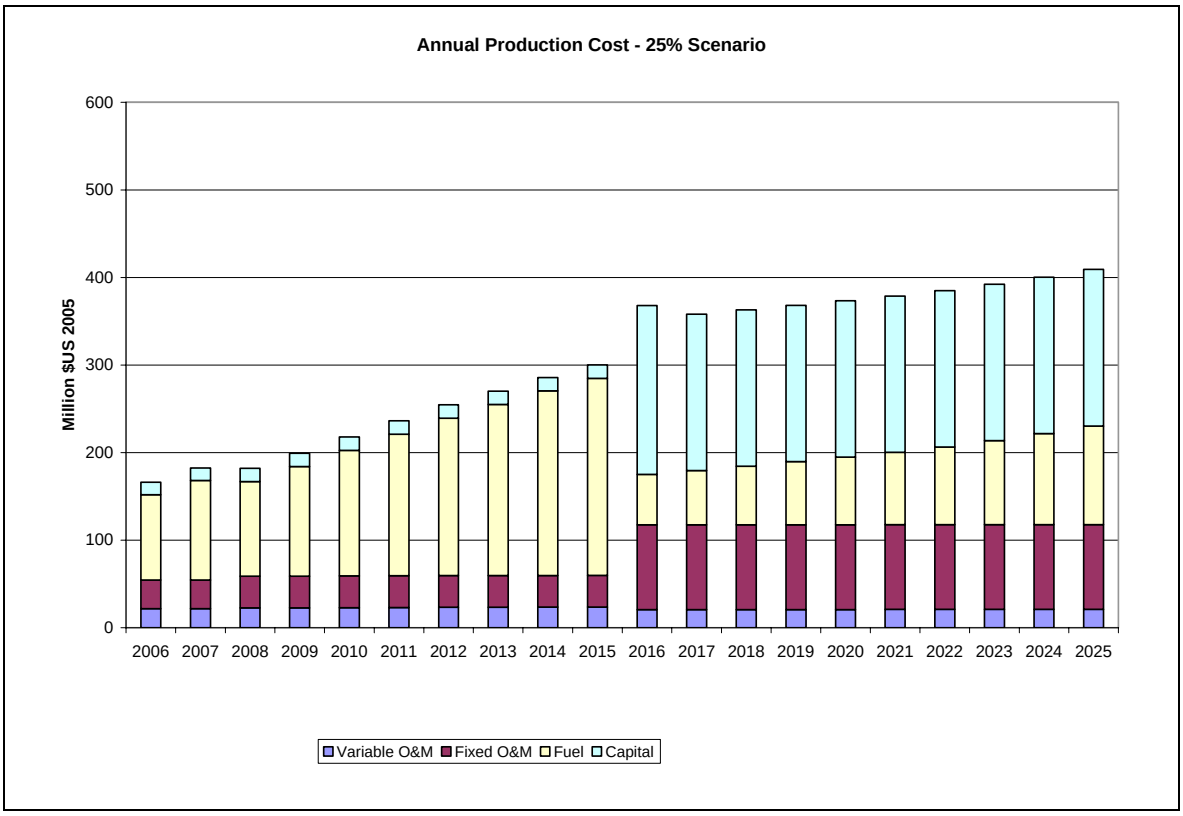


Figure F.12.3. Annual Generation Costs



CASE 13. D0% SCENARIO

Table F.13. Capacity Additions and Retirements for D0% Scenario

Case	Year	2008	2015	2016
D0%	Capacity Addition	Yerevan JBIC	400MW CCGT	
	Capacity Retirement			ANPP16

Figure F.13.1. Generation Capacity by Fuel Type

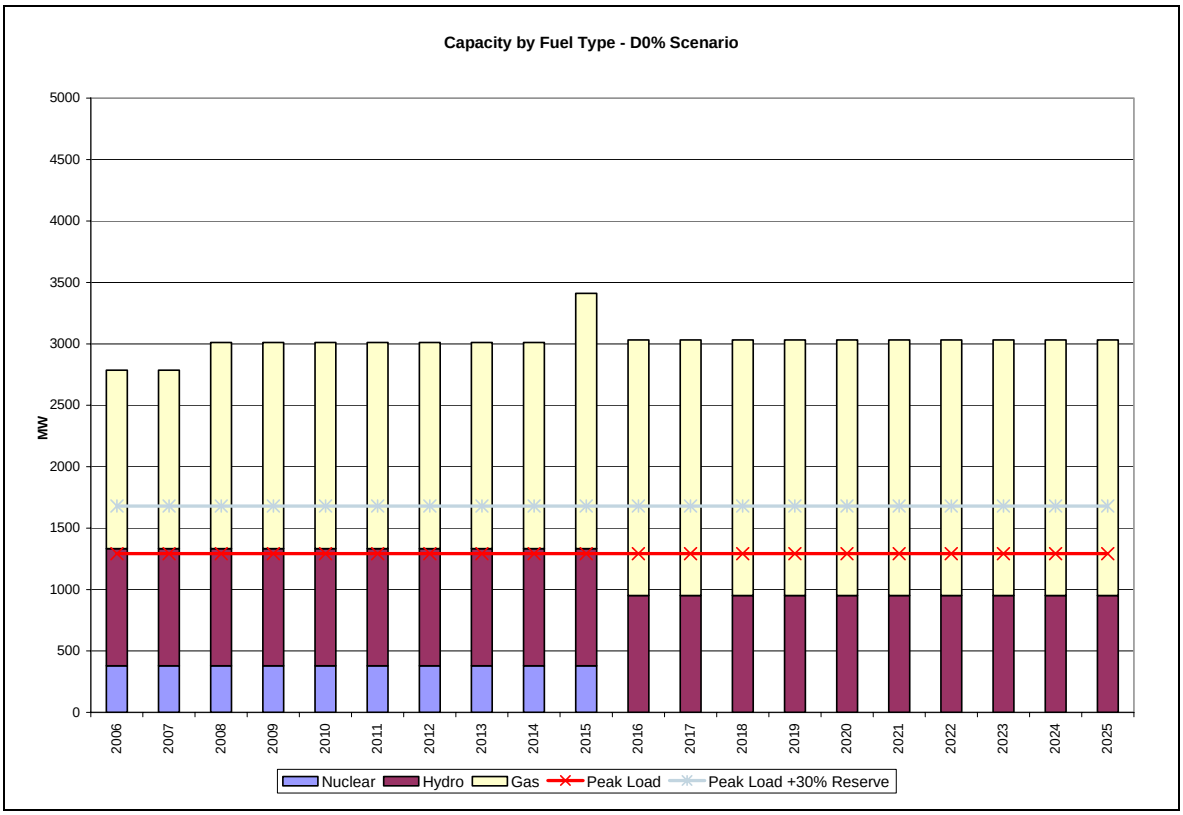


Figure F.13.2. Generation Energy Supply

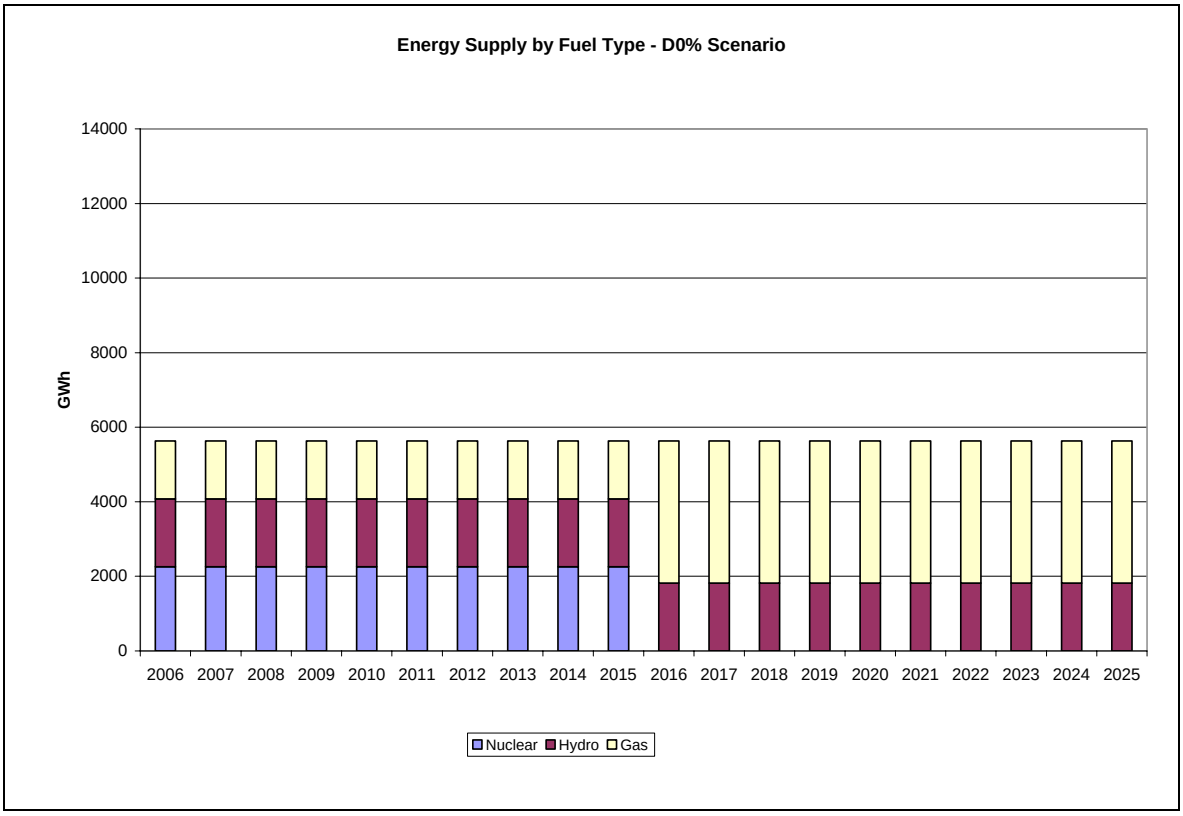
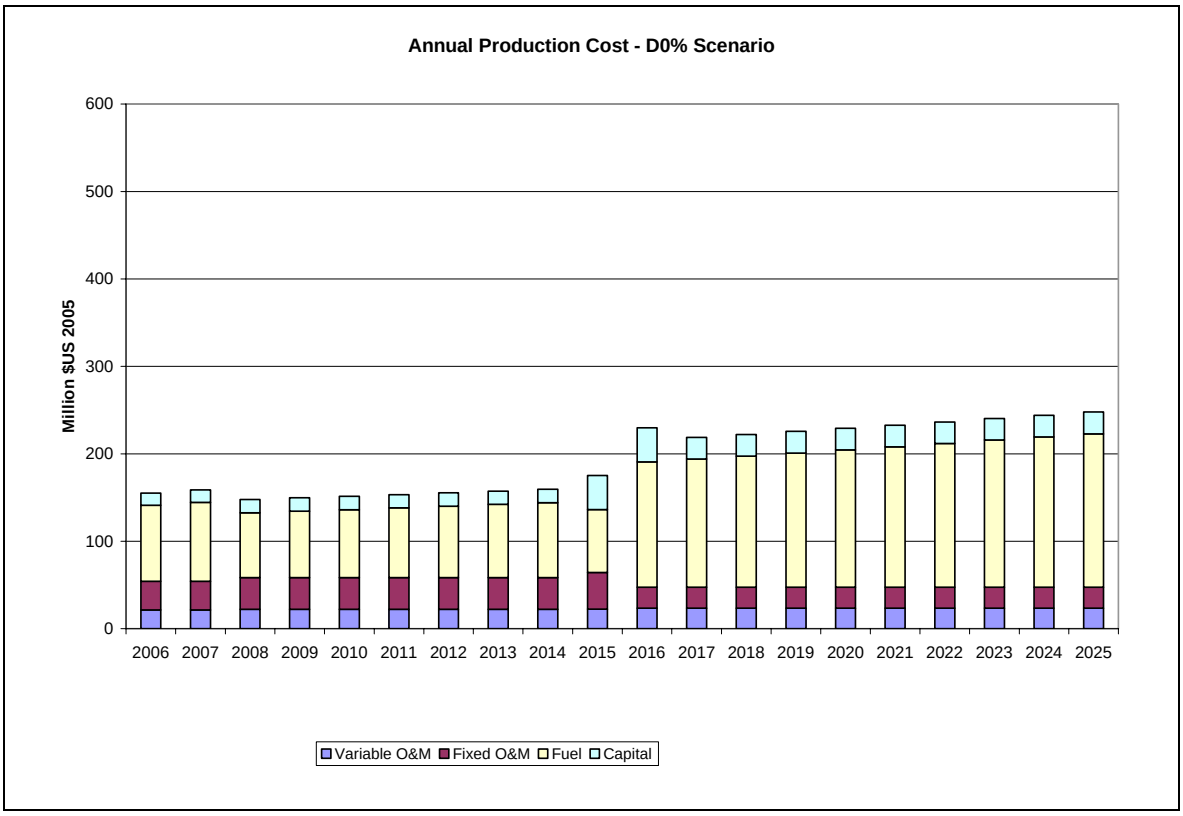


Figure F.13.3. Annual Generation Costsh



CASE 14. D1% SCENARIO

Table F.14. Capacity Additions and Retirements for D1% Scenario

Case	Year	2008	2011	2016	2022
D1%	Capacity Addition	Yerevan JBIC	400MW CCGT		400MW CCGT
	Capacity Retirement			ANPP16	

Figure F.14.1. Generation Capacity by Fuel Type

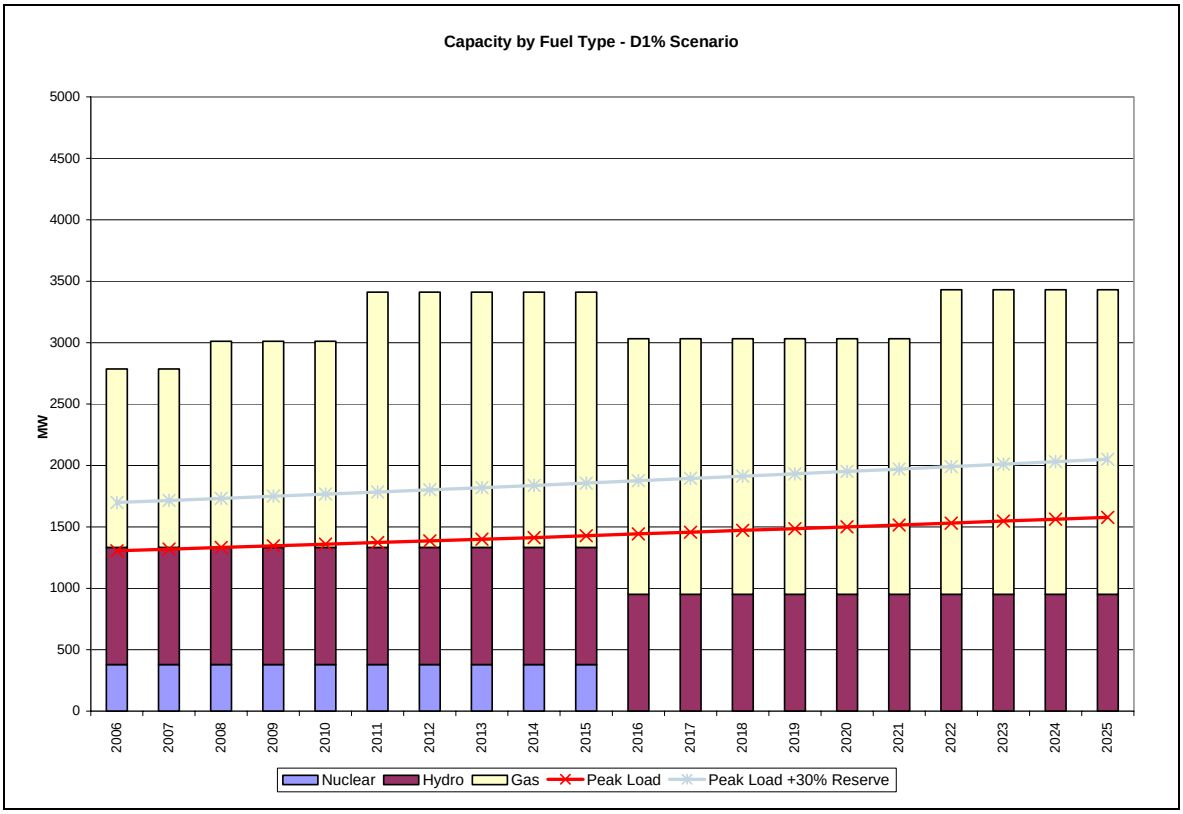


Figure F.14.2. Generation Energy Supply

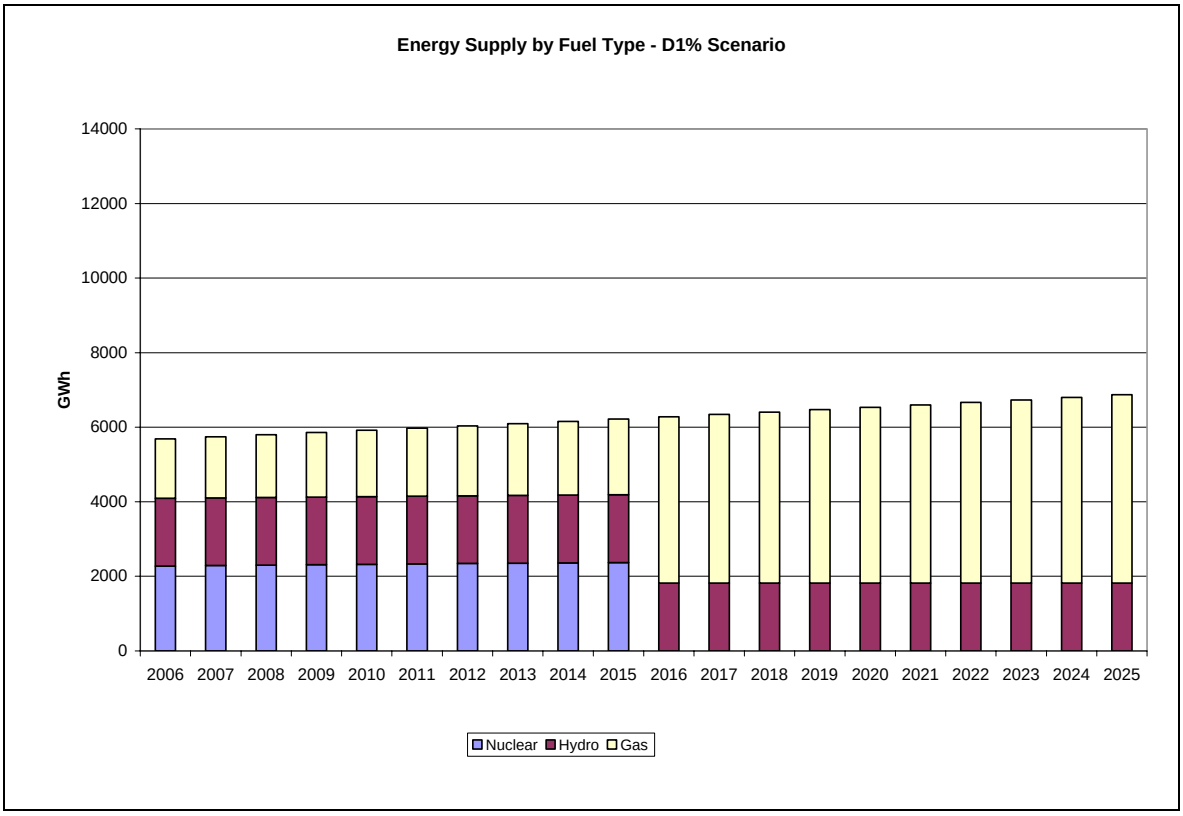
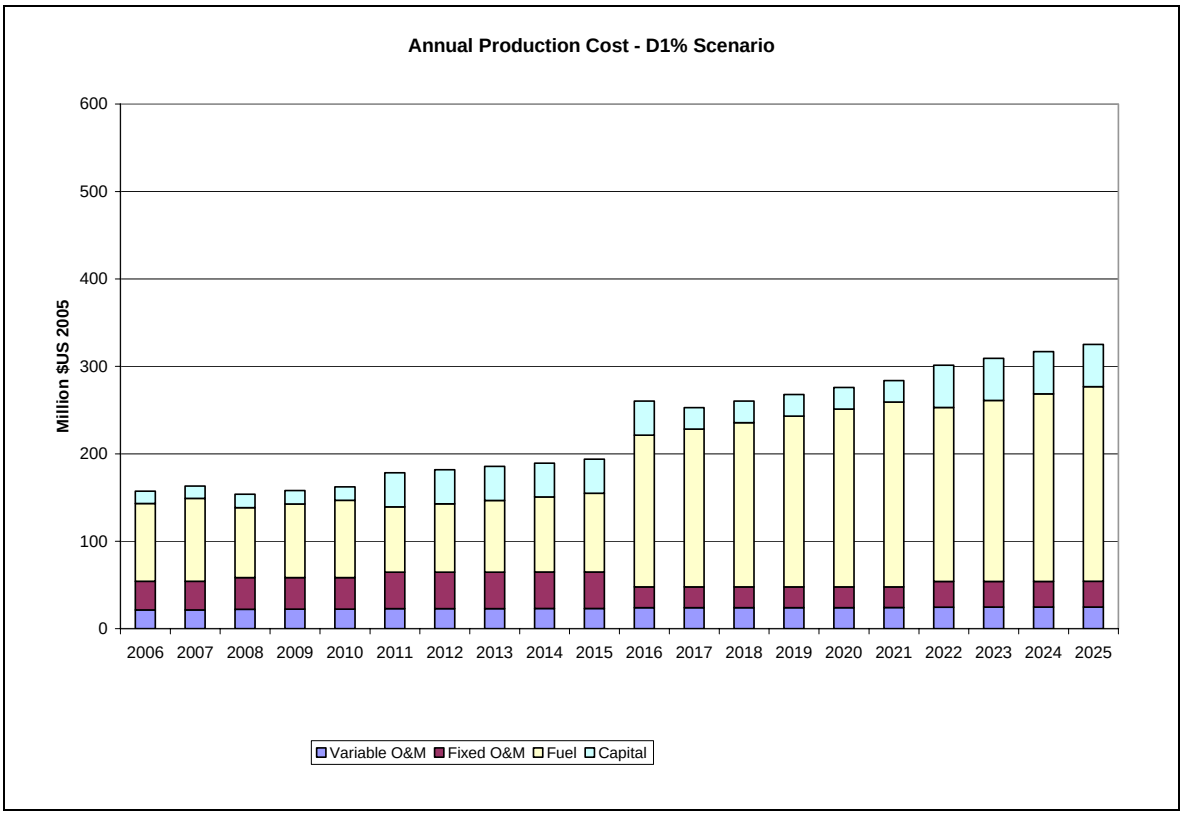


Figure F.14.3. Annual Generation Costs



CASE 15. LT SCENARIO

Table F.15. Capacity Additions and Retirements for LT Scenario

Case	Year	2008	2009	2016
LT	Capacity Addition	Yerevan JBIC	400MW CCGT	ACR 1000
	Capacity Retirement			ANPP16

Figure F.15.1. Generation Capacity by Fuel Type

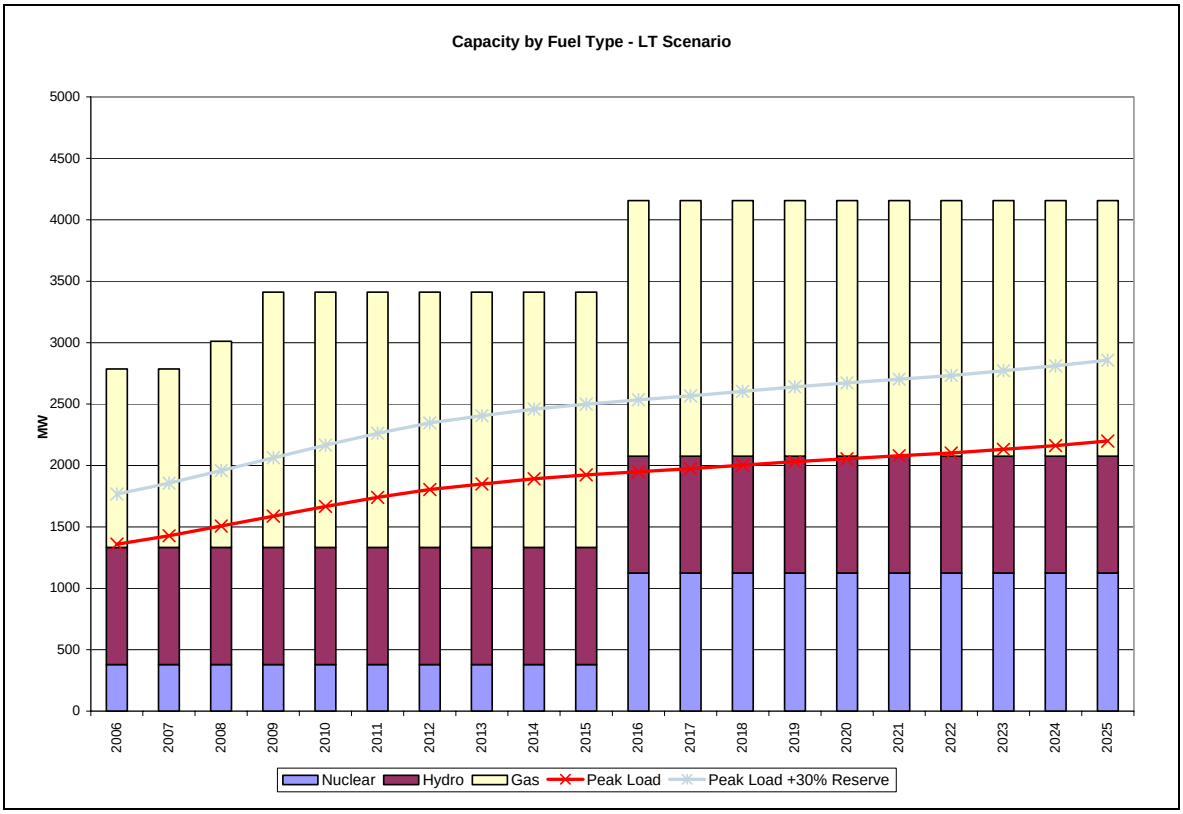


Figure F.15.2. Generation Energy Supply

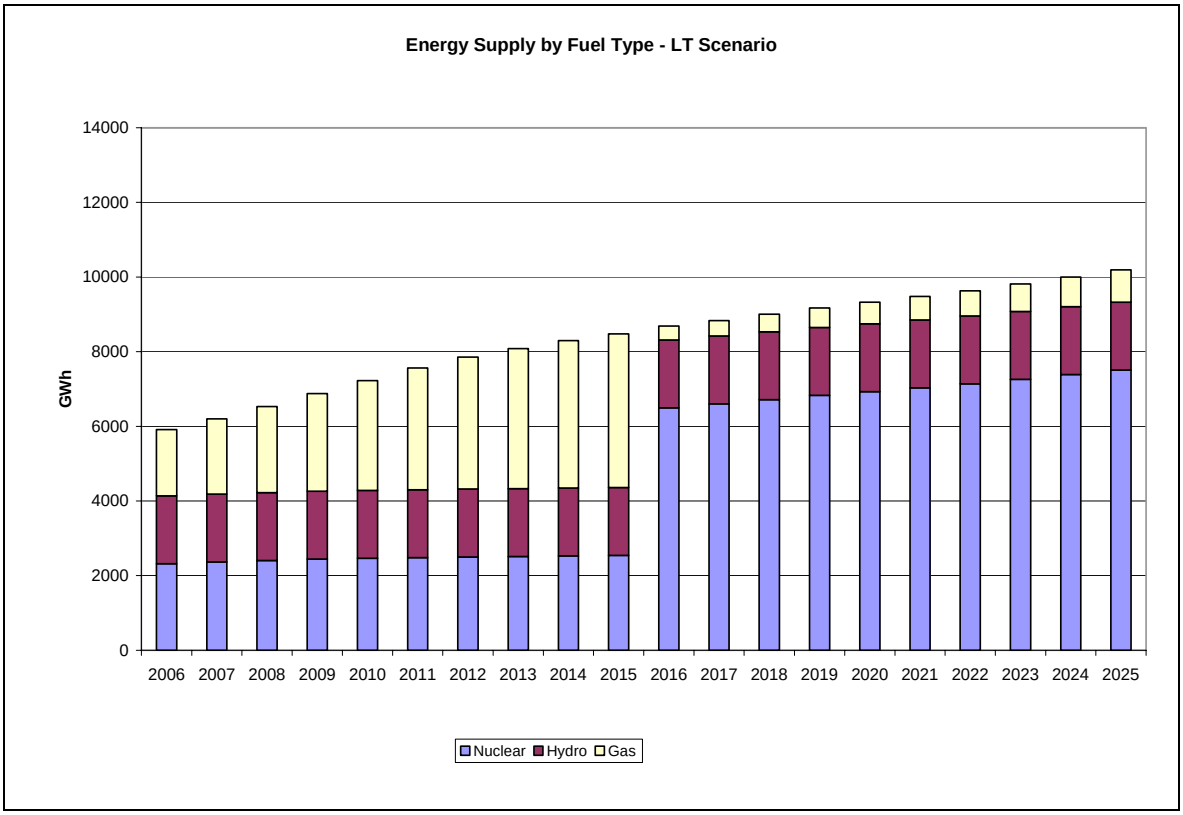
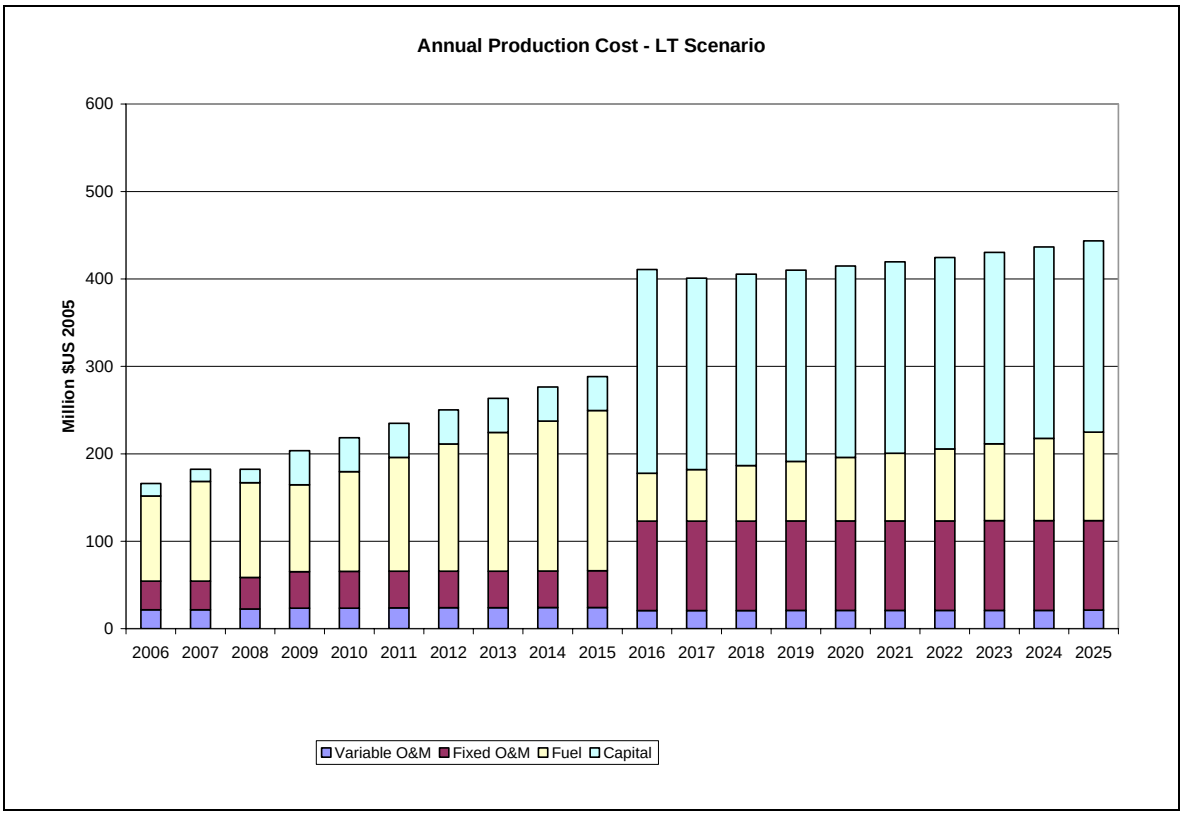


Figure F.15.3. Annual Generation Costs



CASE 16. SMP SCENARIO

Table F.16. Capacity Additions and Retirements for SMP Scenario

Case	Year	2008	2011	2016	2017
SMP	Capacity Addition	Yerevan JBIC Hrazdan 5	Yerevan Commercial Loriberd 60	ACR 1000	Shnokh 75
	Capacity Retirement			ANPP16	

Figure F.16.1. Generation Capacity by Fuel Type

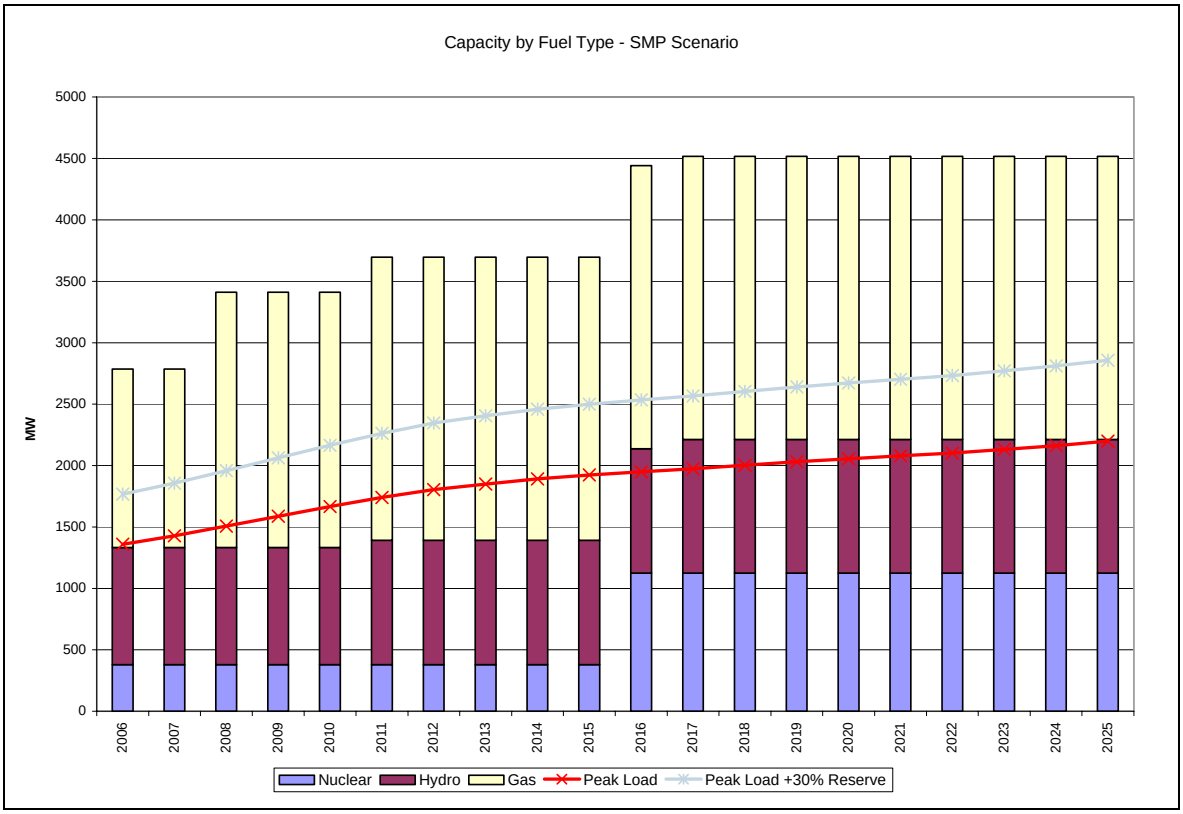


Figure F.16.2. Generation Energy Supply

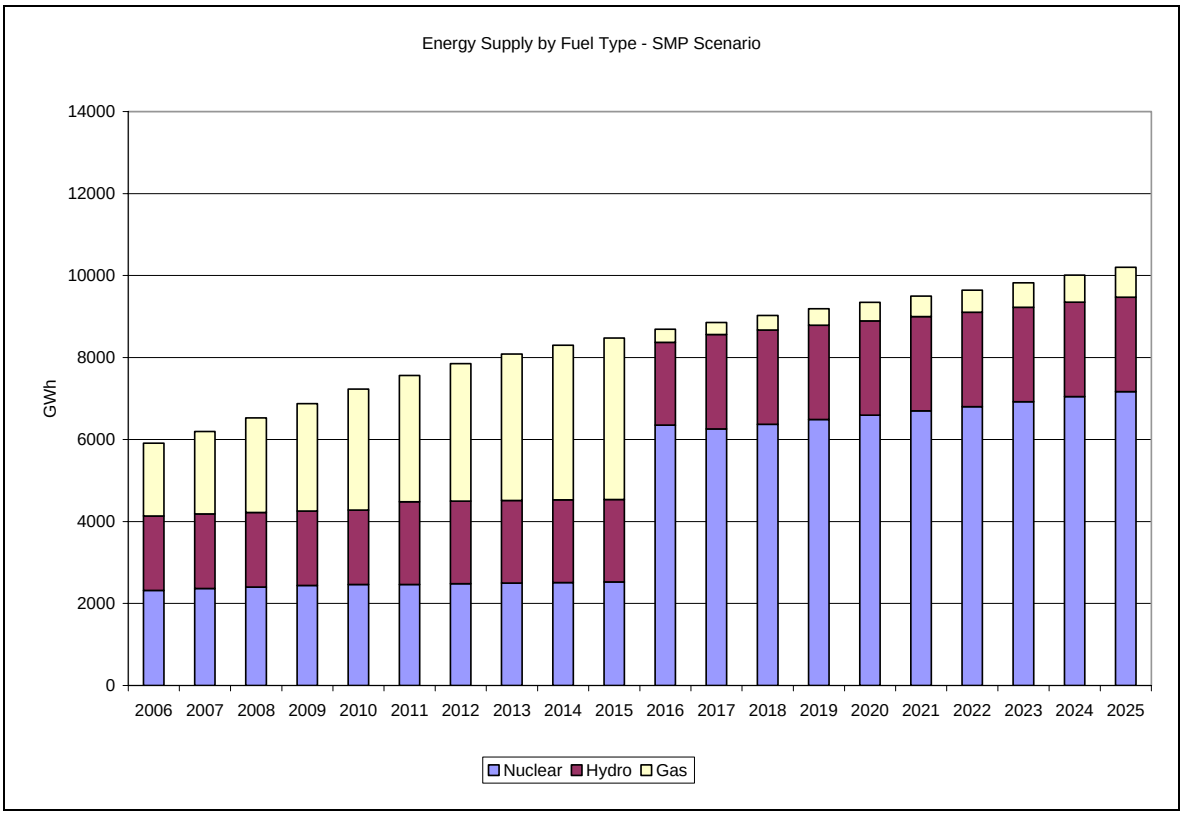
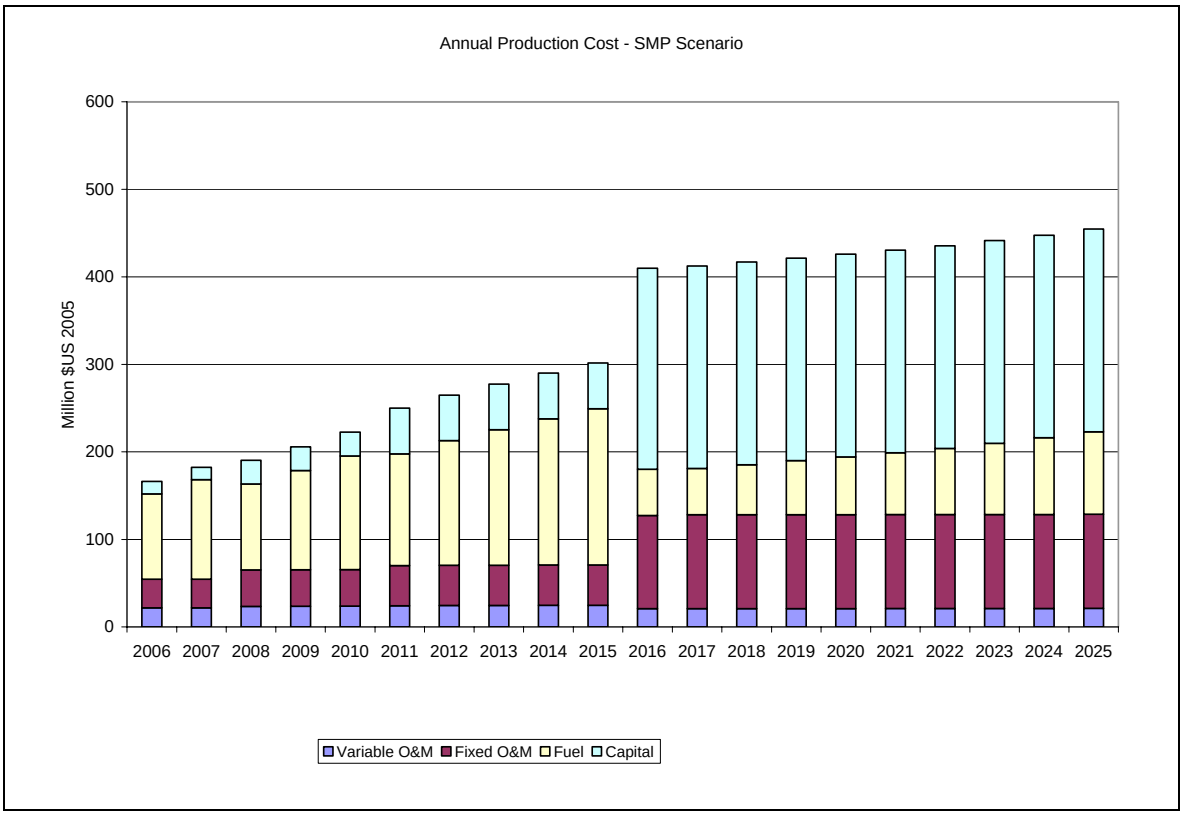


Figure F.16.3. Annual Generation Costs



3. APPENDIX F-3: TARIFF IMPACT ANALYSIS

The detailed results of the tariff impact analysis are provided in the following pages.

Table 1. Annual Projected Tariff -- Base Economic Scenario

Total Annual Production Cost [MMUS$](*)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Variable O&M	21.6	21.7	22.6	23.5	23.7	23.9	24	24.1	24.3	24.4
Fixed O&M	32.8	32.8	36.2	41.8	41.8	41.8	41.8	41.8	41.8	41.8
Fuel	97.6	113.8	108.1	99.4	114.1	130.2	145.6	158.6	171.5	183.3
Capital	14.1	14.1	15.3	38.9	38.9	38.9	38.9	38.9	38.9	38.9
Total	166.1	182.4	182.2	203.6	218.5	234.8	250.3	263.4	276.5	288.4

Retail Tariff Estimate	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average Costs per kWh of Gross Generation (mills/kWh)	28.11	29.42	27.90	29.61	30.23	31.05	31.87	32.59	33.32	34.03
Auxiliary Needs of Generators (MS)	5.85%	5.43%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	29.86	31.11	29.37	31.16	31.83	32.68	33.54	34.30	35.07	35.82
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	45.85	47.10	45.36	47.15	47.82	48.67	49.53	50.29	51.06	51.81
Retail Tariff (mills/kWh, with VAT)	55.02	56.52	54.43	56.58	57.38	58.41	59.44	60.35	61.27	62.17

Table 1. Annual Projected Tariff -- Base Economic Scenario (continued)

Total Annual Production Cost [MMUS$](*)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Variable O&M	20.7	20.8	20.8	20.9	20.9	21	21	21.1	21.1	21.2
Fixed O&M	102.3	102.3	102.3	102.3	102.3	102.3	102.3	102.3	102.3	102.3
Fuel	54.8	58.8	63.3	68	72.6	77.3	82.3	88.1	94.3	101.2
Capital	216.4	202.3	202.3	202.3	202.3	202.3	202.3	202.3	202.3	202.3
Total	394.2	384.2	388.7	393.5	398.1	402.9	407.9	413.8	420	427

Retail Tariff Estimate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Costs per kWh of Gross Generation (mills/kWh)	45.39	43.49	43.17	42.91	42.70	42.51	42.36	42.17	41.99	41.90
Auxiliary Needs of Generators (MS)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	47.78	45.77	45.45	45.17	44.94	44.75	44.59	44.39	44.20	44.10
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	63.77	61.76	61.44	61.16	60.93	60.74	60.58	60.38	60.19	60.09
Retail Tariff (mills/kWh, with VAT)	76.53	74.12	73.72	73.39	73.12	72.88	72.69	72.45	72.23	72.11

Figure 1. Composition of retail tariff for Base Economic Scenario

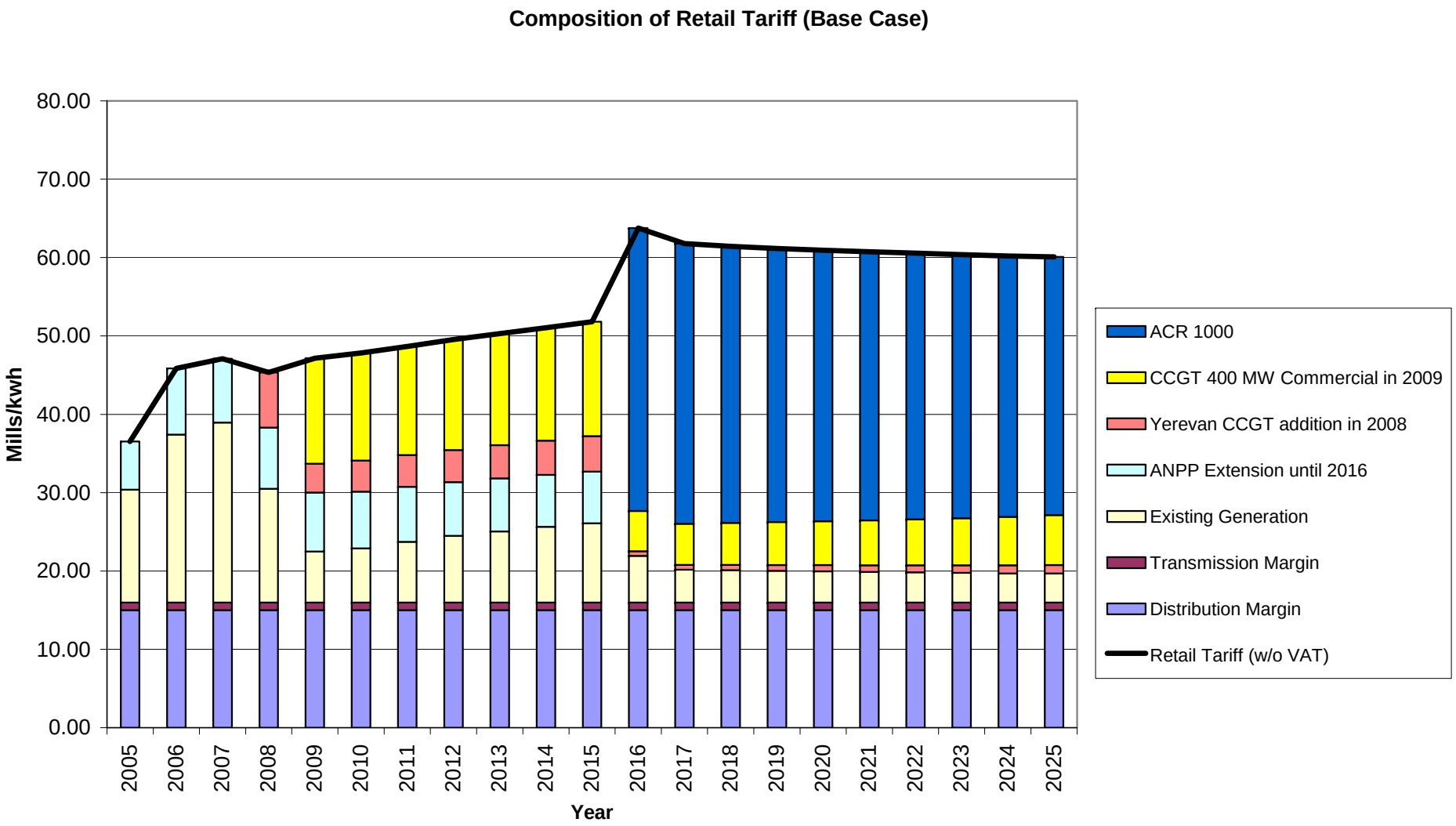


Figure 2. Structure of retail tariff for Base Economic Scenario

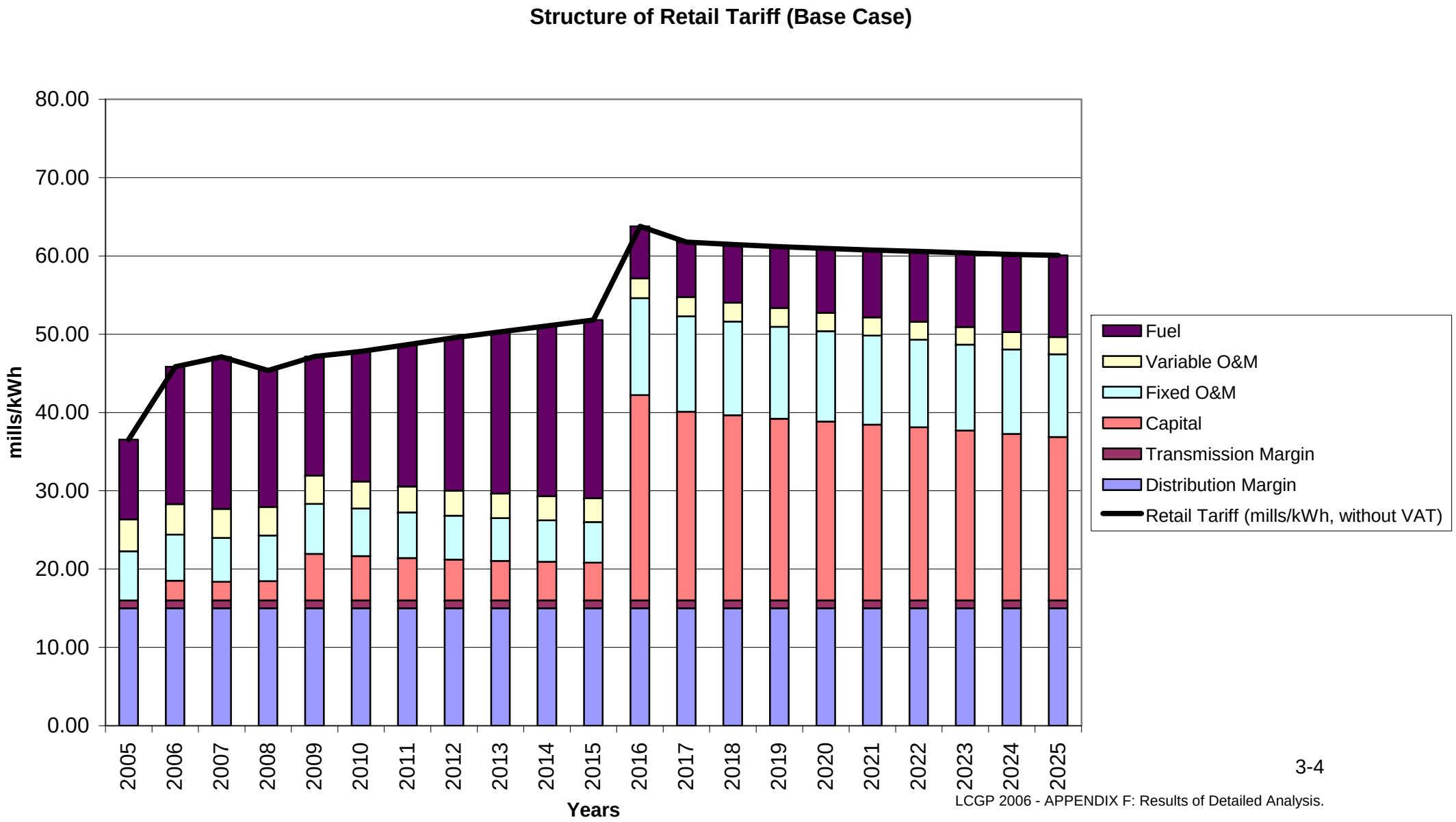


Table 2. Annual Projected Tariff – High WACC Case

Total Annual Production Cost [MMUS$](*)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Variable O&M	21.5	21.6	22.4	22.5	22.6	22.7	22.7	22.8	22.9	23
Fixed O&M	32.8	32.8	36.2	36.2	36.2	36.2	36.2	36.2	36.2	36.2
Fuel	95	106	92.2	102.9	113.7	124.5	136.2	148.9	159.2	169.3
Capital	22.2	22.2	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
Total	171.5	182.6	174.1	184.9	195.8	206.7	218.4	231.2	241.6	251.8

Retail Tariff Estimate	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average Costs per kWh of Gross Generation (mills/kWh)	29.36	30.38	28.42	29.21	29.97	30.74	31.59	32.49	33.29	34.10
Auxiliary Needs of Generators (MS)	5.85%	5.43%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	31.19	32.12	29.92	30.74	31.55	32.35	33.26	34.20	35.04	35.89
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	47.18	48.11	45.91	46.73	47.54	48.34	49.25	50.19	51.03	51.88
Retail Tariff (mills/kWh, with VAT)	56.61	57.73	55.09	56.08	57.05	58.01	59.09	60.23	61.24	62.26

Table 2. Annual Projected Tariff – High WACC Case (Continued)

Total Annual Production Cost [MMUS$](*)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Variable O&M	20.5	20.5	20.5	20.5	20.5	20.5	20.6	20.6	20.6	20.6
Fixed O&M	96.79	96.79	96.79	96.79	96.79	96.79	96.79	96.79	96.79	96.79
Fuel	39.9	42.1	44.4	46.8	49.5	52.4	55.6	58.9	62.5	67
Capital	319.9	297.8	297.8	297.8	297.8	297.8	297.8	297.8	297.8	297.8
Total	477.09	457.19	459.49	461.89	464.59	467.49	470.79	474.09	477.69	482.19

Retail Tariff Estimate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Costs per kWh of Gross Generation (mills/kWh)	63.17	59.72	59.21	58.80	58.47	58.21	58.01	57.82	57.65	57.60
Auxiliary Needs of Generators (MS)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	66.50	62.87	62.33	61.90	61.55	61.27	61.06	60.87	60.68	60.63
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	82.49	78.86	78.32	77.89	77.54	77.26	77.05	76.86	76.67	76.62
Retail Tariff (mills/kWh, with VAT)	98.99	94.63	93.98	93.46	93.04	92.72	92.46	92.23	92.01	91.95

Figure 3. Composition of Retail Tariff – High WACC Case.

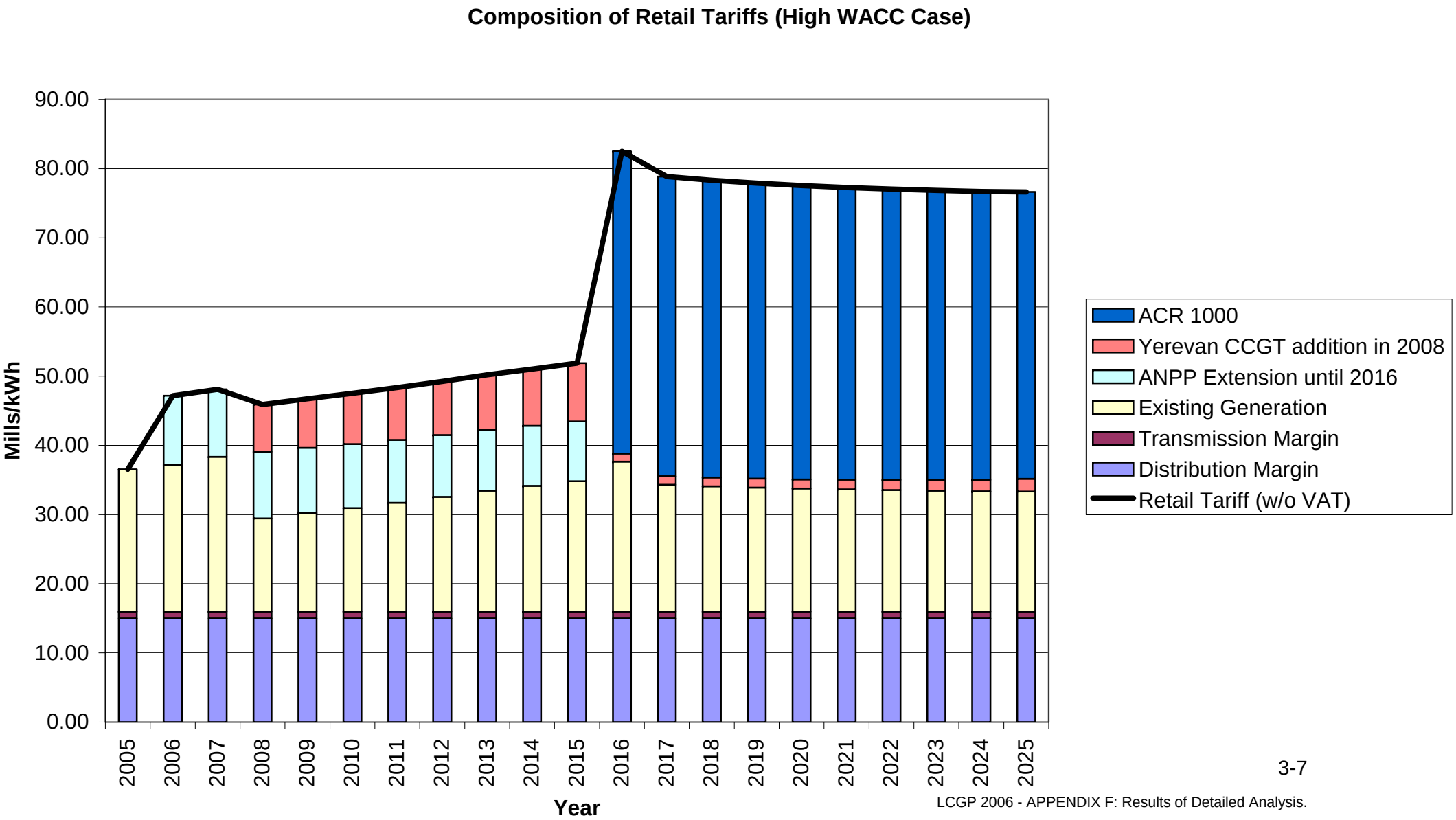


Figure 4. Structure of Retail Tariff – High WACC Case.

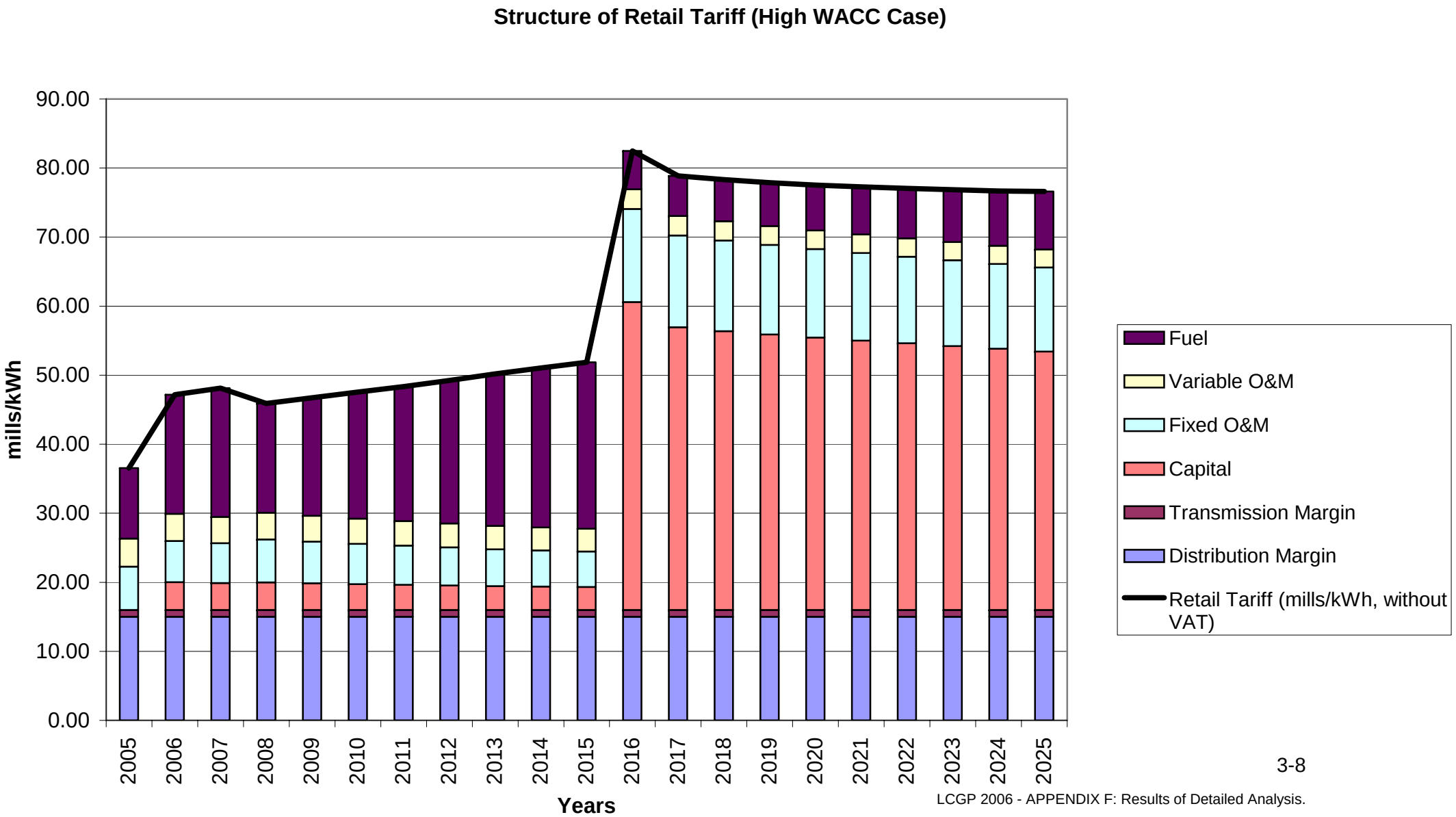


Table 3. Annual Projected Tariff – Thermal Retirement Case

Total Annual Production Cost [MMUS$](*)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Variable O&M	21.6	21.7	22.6	23.5	23.7	23.9	24	24.1	24.3	24.4
Fixed O&M	32.8	32.8	36.2	41.8	41.8	41.8	41.8	41.8	41.8	41.8
Fuel	97.6	113.8	108.1	99.4	114.1	130.2	145.6	158.6	171.5	183.3
Capital	14.1	14.1	15.3	38.9	38.9	38.9	38.9	38.9	38.9	38.9
Total	166.1	182.4	182.2	203.6	218.5	234.8	250.3	263.4	276.5	288.4

Retail Tariff Estimate	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average Costs per kWh of Gross Generation (mills/kWh)	28.11	29.42	27.90	29.61	30.23	31.05	31.87	32.59	33.32	34.03
Auxiliary Needs of Generators (MS)	5.85%	5.43%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	29.86	31.11	29.37	31.16	31.83	32.68	33.54	34.30	35.07	35.82
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	45.85	47.10	45.36	47.15	47.82	48.67	49.53	50.29	51.06	51.81
Retail Tariff (mills/kWh, with VAT)	55.02	56.52	54.43	56.58	57.38	58.41	59.44	60.35	61.27	62.17

Table 3. Annual Projected Tariff – Thermal Retirement Case (Continued)

Total Annual Production Cost [MMUS$](*)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Variable O&M	20.7	20.8	20.8	20.9	20.9	21	21	21.1	21.1	21.2
Fixed O&M	93.99	93.99	93.99	92.49	92.49	92.49	92.49	92.49	92.49	92.49
Fuel	54.8	58.8	63.3	68	72.6	77.3	82.3	88.1	94.3	101.2
Capital	216.4	202.3	202.3	202.3	202.3	202.3	202.3	202.3	202.3	202.3
Total	385.89	375.89	380.39	383.69	388.29	393.09	398.09	403.99	410.19	417.19

Retail Tariff Estimate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Costs per kWh of Gross Generation (mills/kWh)	44.44	42.55	42.25	41.84	41.64	41.47	41.34	41.17	41.01	40.93
Auxiliary Needs of Generators (MS)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	46.78	44.78	44.48	44.04	43.84	43.66	43.51	43.34	43.17	43.09
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	62.77	60.77	60.47	60.03	59.83	59.65	59.50	59.33	59.16	59.08
Retail Tariff (mills/kWh, with VAT)	75.32	72.93	72.56	72.04	71.79	71.58	71.41	71.19	70.99	70.89

Figure 5. Composition of Retail tariff – Thermal Retirement Case

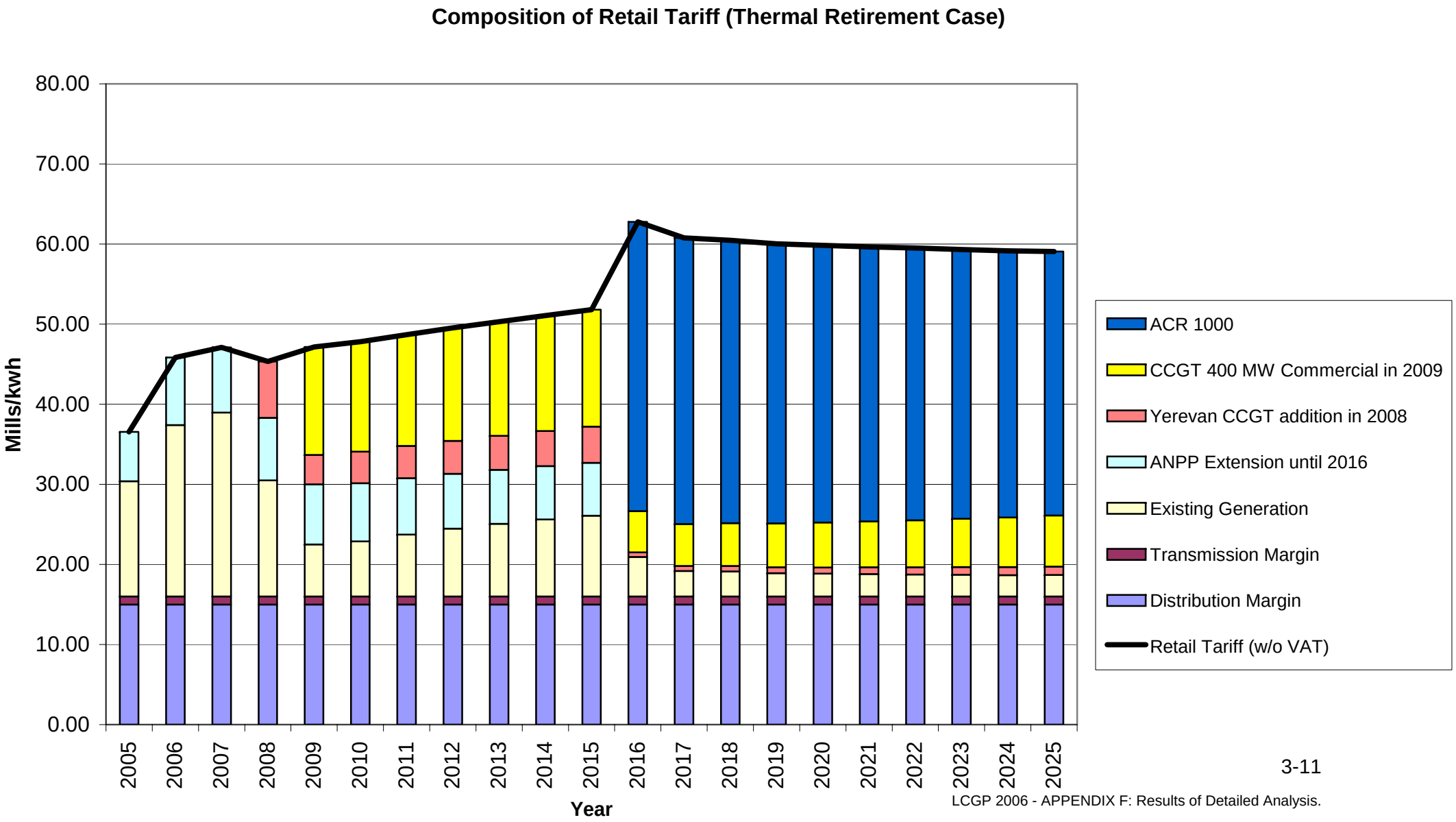


Figure 6. Structure of Retail tariff – Thermal Retirement Case

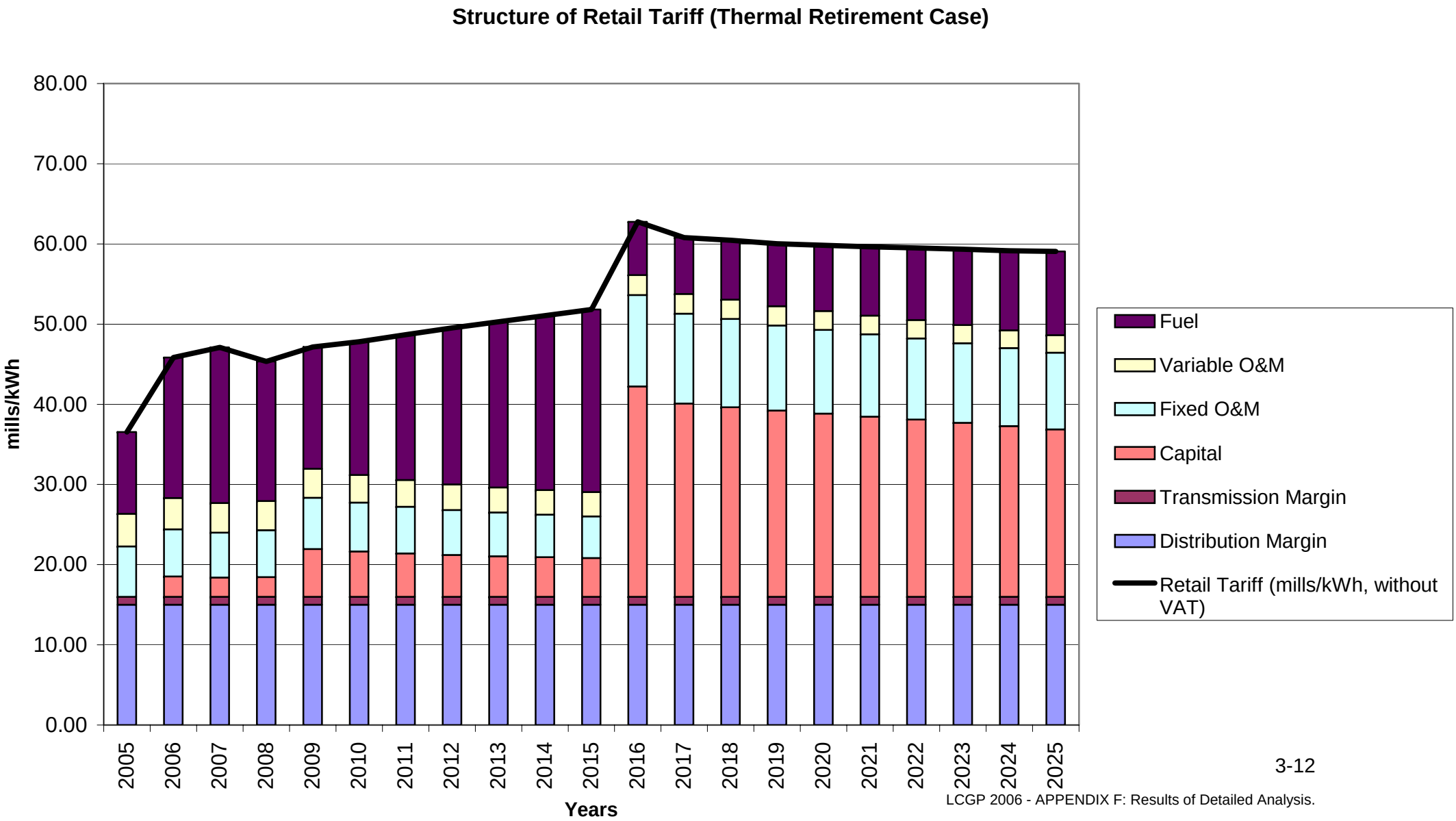


Table 4. Annual Projected Tariff – Yerevan Commercial Case

Total Annual Production Cost [MMUS$](*)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Variable O&M	21.6	21.7	21.8	23	23.2	23.3	23.5	23.6	23.7	23.8
Fixed O&M	32.8	32.8	32.8	38.4	38.4	38.4	38.4	38.4	38.4	38.4
Fuel	97.6	113.8	131.7	111	127.5	144.7	161.2	175.4	189.5	202.4
Capital	14.1	14.1	14.1	37.7	37.7	37.7	37.7	37.7	37.7	37.7
Total	166.1	182.4	200.4	210.1	226.8	244.1	260.8	275.1	289.3	302.3

Retail Tariff Estimate	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average Costs per kWh of Gross Generation (mills/kWh)	28.11	29.42	30.68	30.55	31.38	32.28	33.21	34.04	34.86	35.67
Auxiliary Needs of Generators (MS)	5.85%	5.43%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	29.86	31.11	32.30	32.16	33.03	33.98	34.95	35.83	36.69	37.55
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	45.85	47.10	48.29	48.15	49.02	49.97	50.94	51.82	52.68	53.54
Retail Tariff (mills/kWh, with VAT)	55.02	56.52	57.95	57.78	58.83	59.96	61.13	62.18	63.22	64.24

Table 4. Annual Projected Tariff – Yerevan Commercial Case (Continued)

Total Annual Production Cost [MMUS$](*)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Variable O&M	20.7	20.8	20.8	20.8	20.9	20.9	20.9	21	21	21.1
Fixed O&M	98.99	98.99	98.99	98.99	98.99	98.99	98.99	98.99	98.99	98.99
Fuel	54.9	59.2	64	69.1	74	79.1	84.5	90.7	97.4	104.6
Capital	215.3	201.1	201.1	201.1	201.1	201.1	201.1	201.1	201.1	201.1
Total	389.89	380.09	384.89	389.99	394.99	400.09	405.49	411.79	418.49	425.79

Retail Tariff Estimate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Costs per kWh of Gross Generation (mills/kWh)	44.90	43.02	42.75	42.53	42.36	42.21	42.11	41.96	41.84	41.78
Auxiliary Needs of Generators (MS)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	47.27	45.29	45.00	44.77	44.59	44.43	44.32	44.17	44.04	43.98
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	63.26	61.28	60.99	60.76	60.58	60.42	60.31	60.16	60.03	59.97
Retail Tariff (mills/kWh, with VAT)	75.91	73.53	73.19	72.91	72.70	72.51	72.38	72.19	72.04	71.96

Figure 7. Composition of Retail Tariff – Yerevan Commercial Case

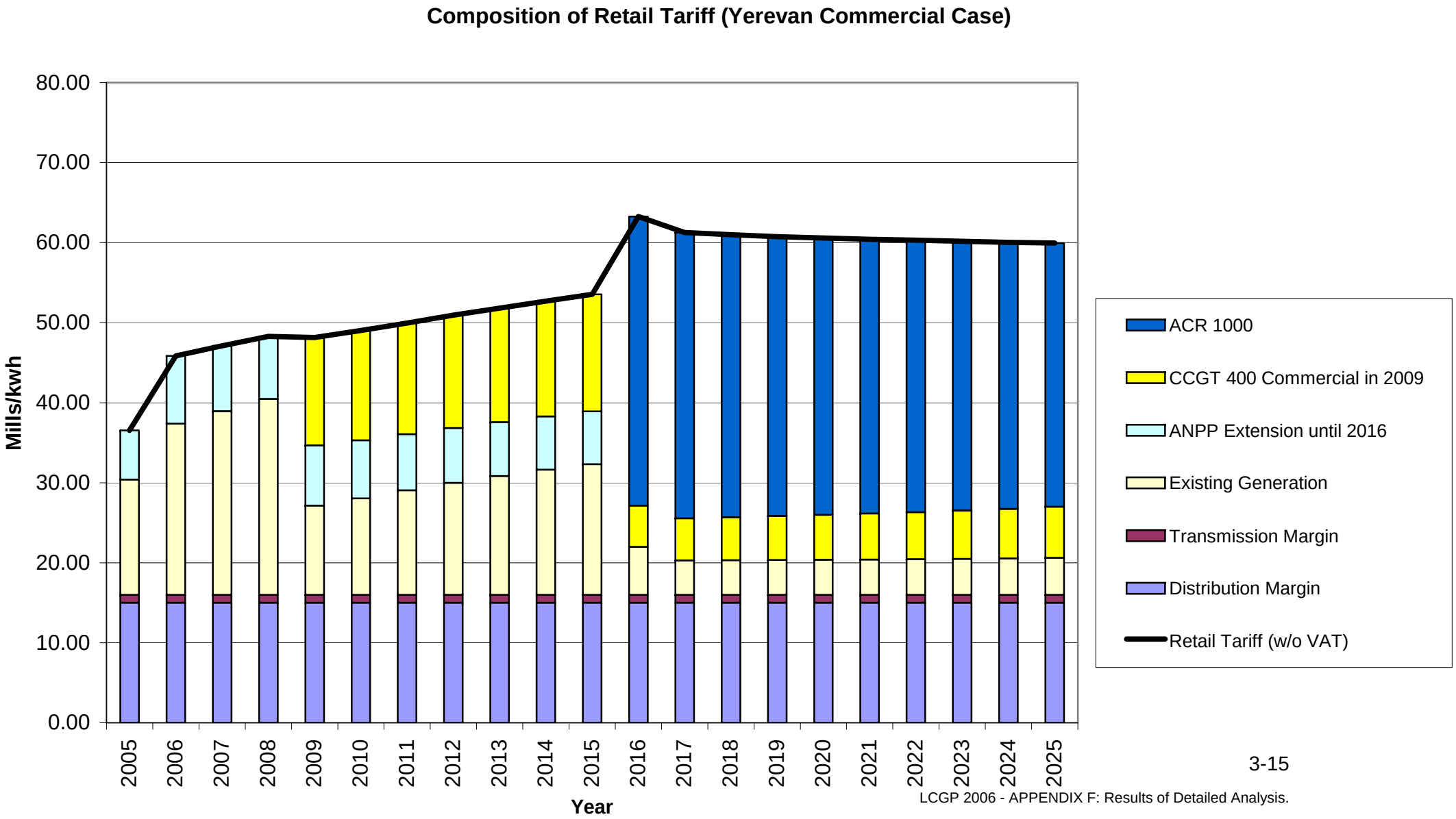


Figure 8. Structure of Retail Tariff – Yerevan Commercial Case

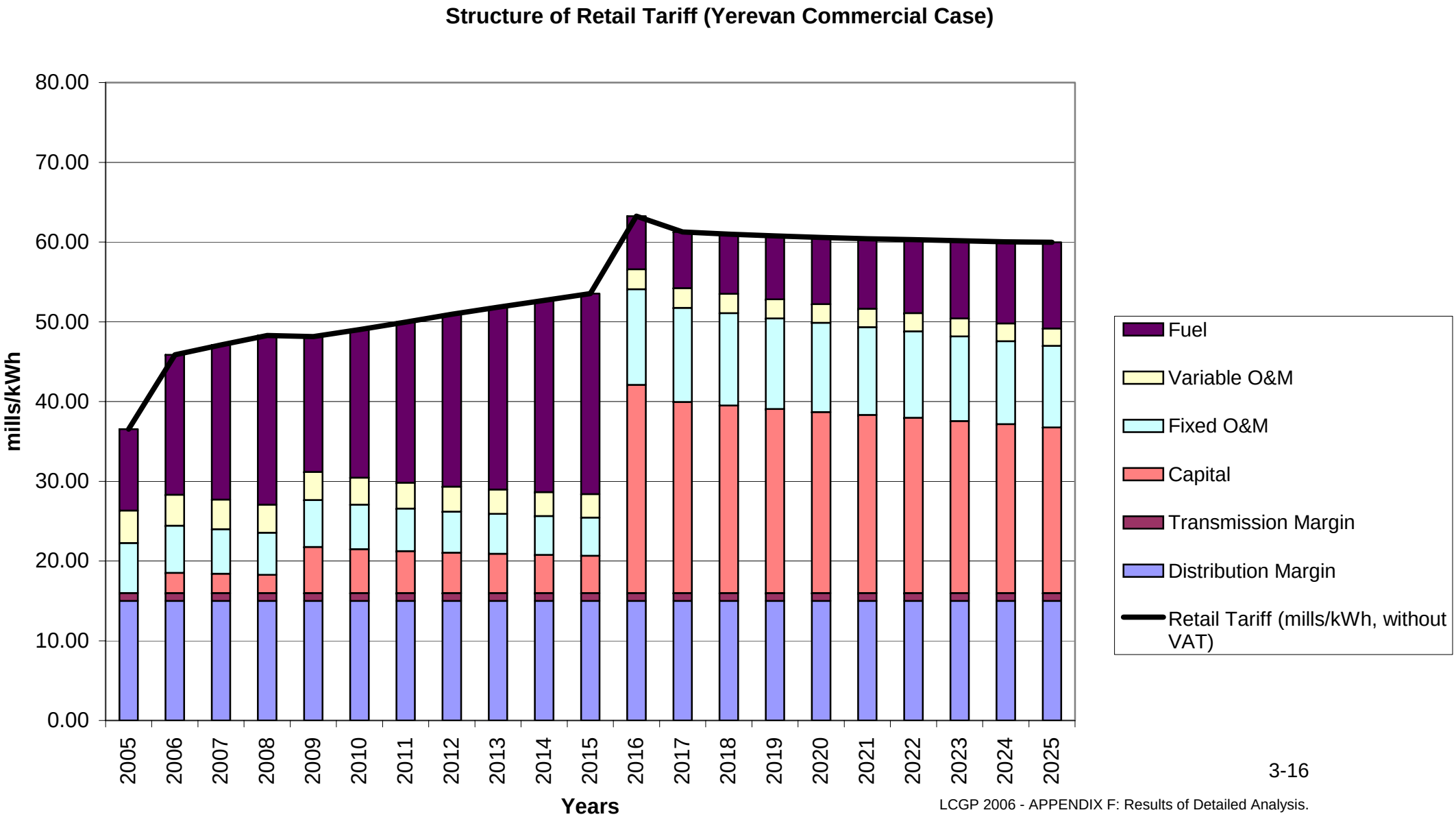


Table 5. Annual Projected Tariff – Strategy Plan of the MoE

Total Annual Production Cost [MMUS$](*)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Variable O&M	21.6	21.7	23.3	23.5	23.8	24.1	24.4	24.5	24.7	24.8
Fixed O&M	32.8	32.8	41.8	41.8	41.8	46	46	46	46	46
Fuel	97.6	113.8	98.1	113.4	129.8	127.7	142.3	154.7	167.2	178.6
Capital	14.1	14.1	27.1	27.1	27.1	52.2	52.2	52.2	52.2	52.2
Total	166.1	182.4	190.3	205.8	222.5	250	264.9	277.4	290.1	301.6

Retail Tariff Estimate	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average Costs per kWh of Gross Generation (mills/kWh)	28.11	29.43	29.14	29.93	30.79	33.06	33.72	34.32	34.95	35.58
Auxiliary Needs of Generators (MS)	5.85%	5.43%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	29.86	31.12	30.67	31.51	32.41	34.80	35.50	36.13	36.79	37.46
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	45.85	47.11	46.66	47.50	48.40	50.79	51.49	52.12	52.78	53.45
Retail Tariff (mills/kWh, with VAT)	55.02	56.53	55.99	56.99	58.08	60.95	61.79	62.54	63.34	64.13

Table 5. Annual Projected Tariff – Strategy Plan of the MoE (Continued)

Total Annual Production Cost [MMUS$](*)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Variable O&M	20.7	20.7	20.7	20.8	20.8	20.9	20.9	21	21	21.1
Fixed O&M	106.59	107.49	107.49	107.49	107.49	107.49	107.4	107.49	107.49	107.49
Fuel	52.8	52.7	57.1	61.6	66	70.6	75.5	81.3	87.6	94.4
Capital	229.7	231.5	231.5	231.5	231.5	231.5	231.5	231.5	231.5	231.5
Total	409.79	412.39	416.79	421.39	425.79	430.49	435.3	441.29	447.59	454.49

Retail Tariff Estimate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Costs per kWh of Gross Generation (mills/kWh)	47.15	46.57	46.19	45.85	45.56	45.33	45.13	44.91	44.70	44.54
Auxiliary Needs of Generators (MS)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	49.63	49.02	48.62	48.26	47.96	47.71	47.50	47.27	47.05	46.89
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	65.62	65.01	64.61	64.25	63.95	63.70	63.49	63.26	63.04	62.88
Retail Tariff (mills/kWh, with VAT)	78.74	78.01	77.54	77.10	76.74	76.45	76.19	75.91	75.65	75.46

Figure 9. Composition of Retail Traiff – Strategic Plan of the MoE

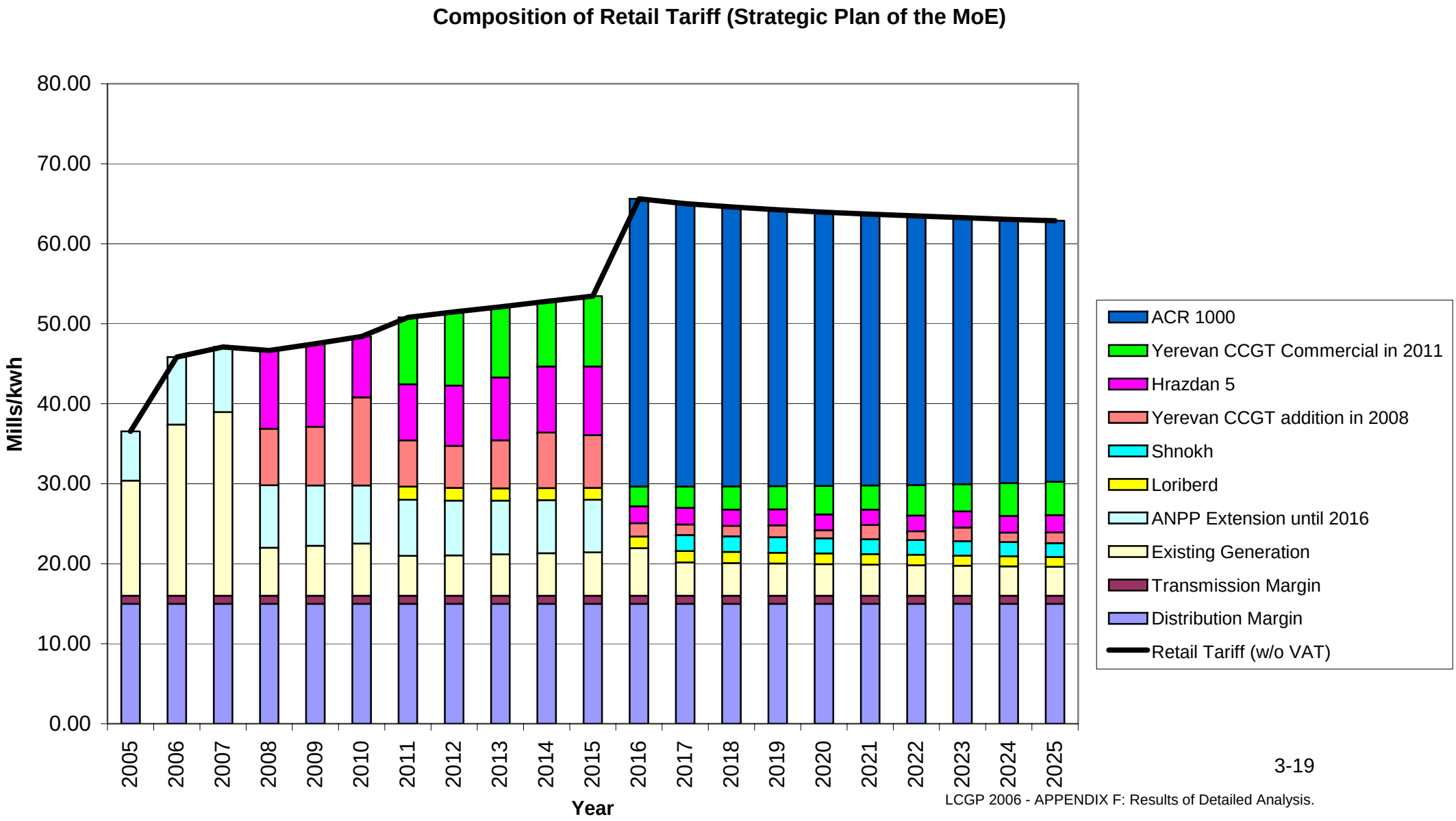


Figure 10. Composition of Retail Traiff – Strategic Plan of the MoE

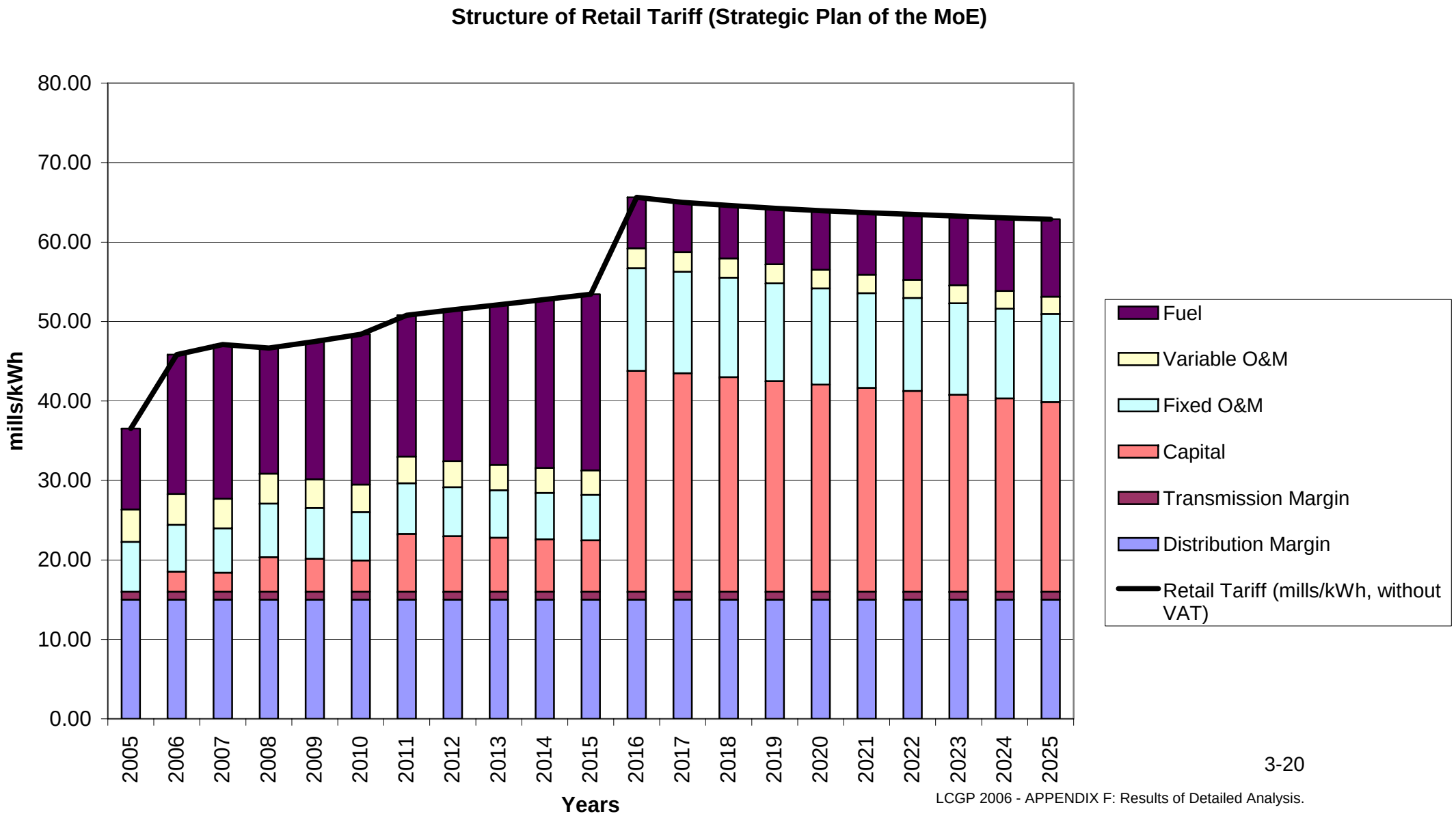


Table 6. Annual Projected Tariff – No Nuclear Case

Total Annual Production Cost [MMUS$](*)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Variable O&M	21.6	21.7	22.6	23.5	23.7	23.9	24	24.1	24.3	24.4
Fixed O&M	32.8	32.8	36.2	41.8	41.8	41.8	41.8	41.8	41.8	41.8
Fuel	97.6	113.8	108.1	99.4	114.1	130.2	145.6	158.6	171.5	183.3
Capital	14.1	14.1	15.3	38.9	38.9	38.9	38.9	38.9	38.9	38.9
Total	166.1	182.4	182.2	203.6	218.5	234.8	250.3	263.4	276.5	288.4

Retail Tariff Estimate	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Average Costs per kWh of Gross Generation (mills/kWh)	28.11	29.42	27.90	29.61	30.23	31.05	31.87	32.59	33.32	34.03
Auxiliary Needs of Generators (MS)	5.85%	5.43%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	29.86	31.11	29.37	31.16	31.83	32.68	33.54	34.31	35.07	35.82
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	45.85	47.10	45.36	47.15	47.82	48.67	49.53	50.30	51.06	51.81
Retail Tariff (mills/kWh, with VAT)	55.02	56.52	54.43	56.58	57.38	58.41	59.44	60.36	61.27	62.17

Table 6. Annual Projected Tariff – No Nuclear Case (Continued)

Total Annual Production Cost [MMUS$](*)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Variable O&M	25.9	26	26.6	26.7	26.8	26.9	27	27.2	27.3	27.5
Fixed O&M	27.19	27.19	30.49	30.49	30.49	30.49	30.49	30.49	30.49	30.49
Fuel	269.9	283.4	284.8	299.7	314.6	329.3	344.8	362.8	381	400.5
Capital	52.9	38.7	52.8	52.8	52.8	52.8	52.8	52.8	52.8	52.8
Total	375.89	375.29	394.69	409.69	424.69	439.49	455.09	473.29	491.59	511.29

Retail Tariff Estimate	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Average Costs per kWh of Gross Generation (mills/kWh)	43.56	42.71	44.06	44.87	45.71	46.53	47.40	48.36	49.27	50.27
Auxiliary Needs of Generators (MS)	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Average Generation Tariff (without VAT)	45.85	44.96	46.38	47.23	48.12	48.98	49.89	50.90	51.86	52.92
Transmission and Market Services Margin (mills/kWh, without VAT)	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
Distribution Margin (mills/kWh, without VAT)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Retail Tariff (mills/kWh, without VAT)	61.84	60.95	62.37	63.22	64.11	64.97	65.88	66.89	67.85	68.91
Retail Tariff (mills/kWh, with VAT)	74.21	73.14	74.84	75.86	76.93	77.96	79.06	80.27	81.42	82.69

Figure 11. Composition of Retail Tariff – No Nuclear Case

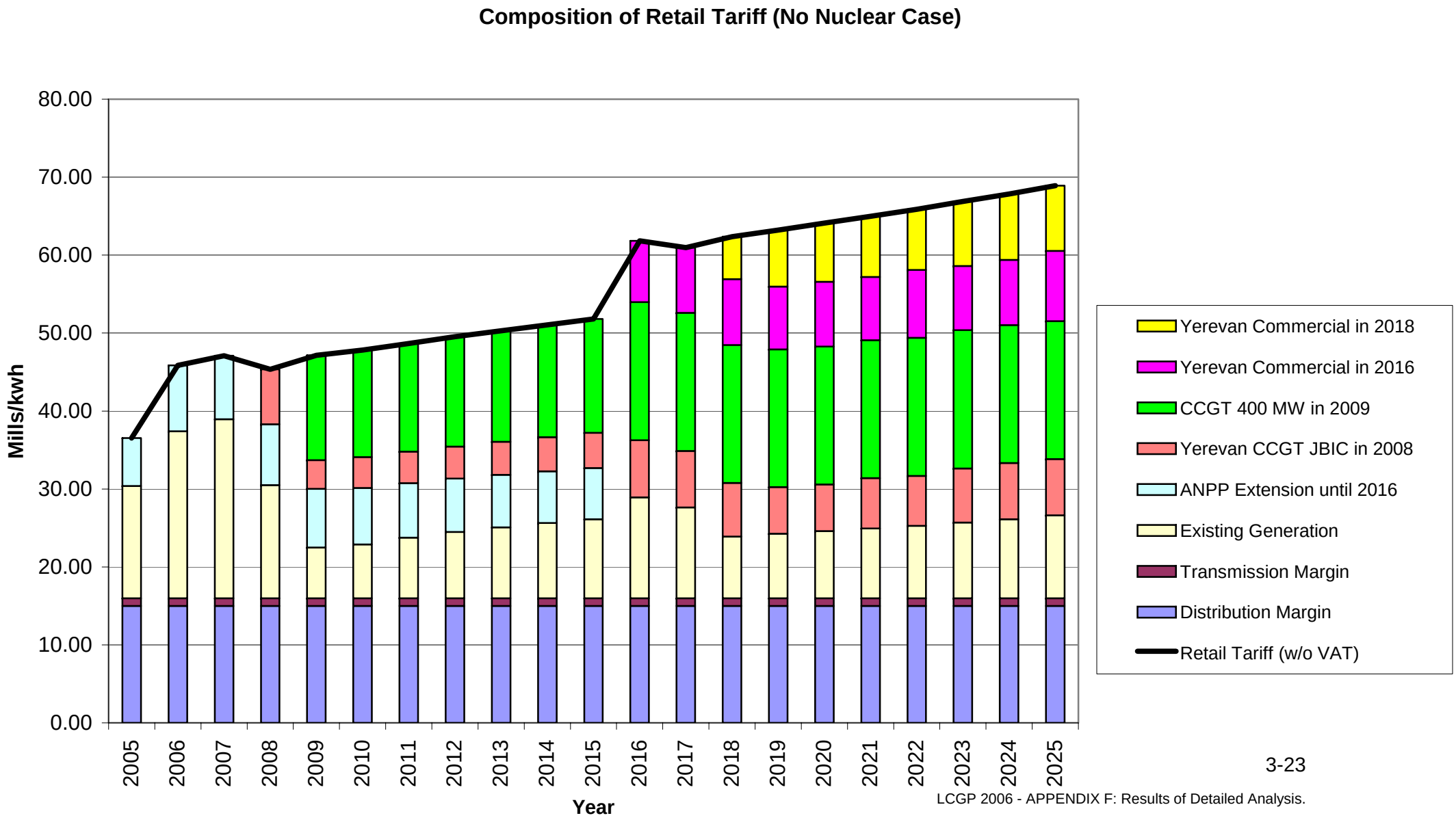
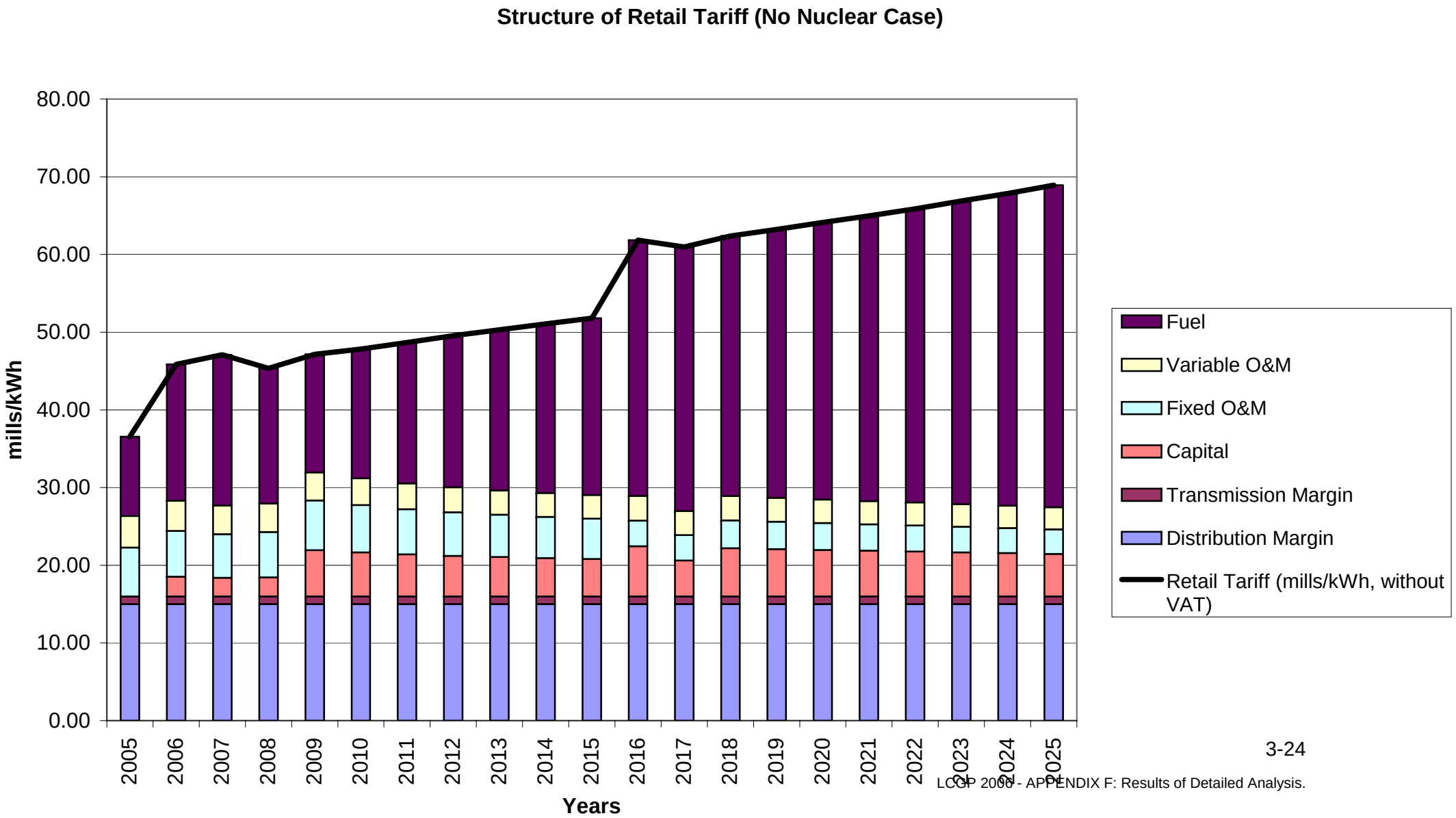



Figure 12. Composition of Retail Tariff – No Nuclear Case