Armenian Power Sector
2002 Least Cost Plan

January 29, 2003

Armenian Power Sector 2002 Least Cost Plan

Contract No. LAG-I-00-98-00005-00

Task Order No. 824

January 29, 2003

Prepared for: United States Agency for International Development ENI/EUR/EI
1300 Pennsylvania Ave., N.W. Suite
5-10 Washington, DC 20523

Prepared by: Michael J. Delphia
Masoud Keyan

PA Consulting Group
1750 Pennsylvania Avenue
NW Washington
DC 20006
Tel: +1 202 442 2000
Fax: +1 202 442 2001
www.paconsulting.com

Version: 1.0

EXECUTIVE SUMMARY

This 2002 Least Cost Plan (LCP) is an update of the extensive efforts of the 2000 Least Cost Generation Plan (LCGP) performed by PA Consulting Group (PA). This 2002 LCP focuses on the retirement of the Armenian Nuclear Power Plant (ANPP), the potential replacements for the ANPP, and the actions needed to secure a long-term power supply for Armenia.

The purpose of this report is to assist the Government of Armenia (GoA) and donor agencies in determining viable solutions for an economic and sustainable program for supplying electric energy to the consumers of Armenia. Of particular concern are the issues surrounding the ANPP such as the timing of its retirement, viable replacements and rate impacts, nuclear plant decommissioning methodologies, the collections of decommissioning funds, and the creation and maintenance of a decommissioning fund.

The 2002 LCP process uses scenario analysis to develop recommendations based on expected future loads, fuel cost, operating and maintenance expenditures and so forth. These recommendations are tested against different versions of the future (such as higher fuel cost, lower loads, higher cost of capital) to determine if the long-term recommendations are still valid under differing conditions.

This LCP provides key findings of the analysis performed in 2002 and a two-year action plan for the power sector that is aligned with the long-term least cost plan.

Study Period

The study period for the 2002 LCP is from the year 2003 to year 2022.

Electric Load Forecast

The peak and energy loads for the total domestic market for Armenia have decreased since 2000. The latest estimate of peak and energy forecasts has a lower starting point and a lower growth rate than that shown in the 2000 LCGP. The annual growth for peak and energy is forecasted to be less than 1 % per year starting from initial values of 5181GWh (energy) and 1089 MW (peak load) in 2003.

Export values were forecasted based on the historic values of exports to Georgia (sales to AES Telasi, SakEnergo and Javakhk), Artsakh (Mountainous Region of Karabakh) and Kashatagh (region between Artsakh and Armenia). The swap with Iran will continue until the ANPP is retired. The total net export for each year is assumed to be less than 400 GWH.

Demand-Side Resources

The energy loads were not reduced by explicit demand-side resource options. There are plenty of options to select, but while the investments to rehabilitate the networks are incomplete and the country is in an extreme surplus capacity situation, energy efficiency programs will only be able to compete for capital when they can beat the low running costs of the system, when the opportunity to make them will otherwise be lost (as in new buildings) or when the impacts of avoiding additional gas imports are reflected in the calculation of the value of energy efficiency.

The load forecast is somewhat dampened by the assumption that expansion of gas system will displace some electricity use over the next five to ten years.

Existing Supply-Side Facilities

The Armenia power sector has about a 100% actual capacity margin. This extremely large margin does not need to be financially covered by either the electric consumers or the GoA. The major plants are the ANPP, the Hrazdan and Yerevan TPPs, and the hydropower plants on the Vorotan and Sevan-Hrazdan Cascades.

The plants have not performed the capital improvements that were mandated in the 1999 O&M study, and worse yet, their O&M budgets have been under-funded for many years. This situation cannot last forever and it puts the continued operation of the plants at risk.

Of particular concern is the ANPP where safety issues and decommissioning have not been addressed financially by the GoA. Both of these issues need to be addressed as soon as possible to protect the public from a nuclear accident, to secure the funds needed to properly decommission the plant, and to provide for the continued safe operation of the plant in order to keep over-all purchase power cost down. The GoA needs to also ensure that a process is developed and followed so that nuclear outages are not extended each year due to nuclear fuel debts. In the 2002 LCP, it is assumed that nuclear fuel would be paid and delivered on time.

Capacity Requirements

The reserve capacity was assumed to be 25% of the annual peak load. This assumption is in line with the reserve requirement developed in the 2000 LCP by the Russian firm, Krzhizhanovsky Institute in Moscow (ENIN), in which Armenia operates in parallel with Iran. The annual peak loads were multiplied by 1.25 to obtain the capacity requirements.

There are many future scenarios that are examined in this 2002 LCP. The base case or base scenario assumes that the ANPP will retire in the fourth quarter of 2008, and that peak and energy loads will grow at about 0.7% per annum. The forecasted generating capacity requirements for the base case is 1360 MW in 2003 rising to 1568 MW in 2022 based on current available information.

Future Supply-Side Options

Several new generation options were analyzed in the LCP process. The natural gas-fired options included re-powering of Hrazdan Unit#5 into a combined cycle, a new combined cycle, and small gas turbines. The re-powering of Hrazdan Unit#5 was not considered after 2006 since the technology is getting very old, and the funding to support the preservation of the facilities is unavailable, EBRD funding having run out in 2001.

Other options included a coal-fired fluidized bed plant built next to a coal mine in Armenia and the Meghri hydropower plant to be built on the Araks River.

Fuels

The price of natural gas is the key driver in the forecast of purchase power costs. The 2002 LCP assumes that the natural gas fuel border prices will rise on average 2.11% per annum over the twenty-year study period. The gas would come from Russia or Turkmenistan.

Financial Factors

General inflation was assumed to rise at 3% per annum over the study period. The cost of capital (and discount rate) was assumed to be 15.7%.

Finding

The key findings in this LCP are:

- 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 of about $250 million on cumulative Net Present Value basis ($2003);
- Many 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.

Two-Year Action Plan

There are many actions that should be completed in the next two years:

- 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 paid to the ANPP so that the plant will continue to operate safely.
- Non-essential power plants should be retired and properly dismantled.
- Operation and maintenance expenses should be paid to all power plants not retired;
- Capital improvements for all hydro and thermal power plants not retired should be included in rates and paid to the power plants so the continued operation of the plants are ensured.
- Priorities should be developed 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).
- The Energy Regulatory Commission (ERC) should develop a plan for minimizing the rate shock at the time of the nuclear plant retirement date.

TABLE OF CONTENTS

Appendices

1. INTRODUCTION AND BACKGROUND

1.1 NEED FOR A LEAST COST PLAN

Comprehensive evaluation of the future of the Armenian power sector is important for the security of the power system and for developing a programmatic approach to a reliable, efficient and cost-effective power sector for the Armenian retail electric consumers. The Least Cost Plan (LCP) provides a vision for the future of the power sector and an action plan for the next few years for the power sector entities consistent with that vision. The analysis performed in the development of the LCP provides the basis for making proper decisions on the future of the power sector.

Several key decisions need to be made by the Energy Regulatory Commission and the GoA in the very near future including:

- Should the ANPP be retired before 2015?
- What are the rate impacts for retail electric consumers for early retirement of the ANPP and how will the ERC manage those rate impacts?
- What standards will govern 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 much capacity and energy at reasonable cost can be expected from new hydropower stations?
- What GoA initiatives should be put in place so that new natural gas connections replace electric heating?
- What areas of energy security provides the largest risks and what strategic actions can/should the GoA take to reduce those risks?
- What should be done with the oldest electric capacity, especially that capacity that is part of the CHPs?
- How can the continued operation of the old thermal plants be guaranteed?

The LCP process provides comprehensive analyses that can provide guidance to the ERC, the Ministry of Energy (MoE), and power market entities on these issues.

1.2 THE 2000 LEAST COST GENERATION PLAN

The 2000 Least Cost Generation Plan (2000 LCGP) developed by PA Consulting followed several general studies that had been completed for the power sector including the 1994 and 1996 Lahmeyer, Inc. reports, *The Least Cost Power Sector Investment Program*. The 2000 LCGP was first extensive least cost plan completed for the Armenian power sector and it set the framework for future LCP efforts. The 2002 LCP has included the basic process used in the 2000 LCGP with some improvements in the process as well as an update of the assumptions and data used in the analyses.

1.3 EU/ARMENIA AGREEMENT ON THE CLOSURE OF THE ANPP

Several years ago the Government of Armenia and the European Union agreed on the closing of the ANPP by 2004 or whenever a viable alternative could be identified and brought on-line. To date, no viable alternative has been identified and the earliest date that EU consultants think that a replacement could be ready, even if it was not viable, is 2008. The EU has promised Euro 100 million (about $100 million) toward the replacement resources for the ANPP. The replacement of the ANPP will require much more than this. . Without additional donor financing or foreign investment into new generation, there are not enough available funds to replace the ANPP in the near future.

The EBRD recently withdrew from the purchase of a 19.9% equity share of the distribution company. The distribution privatization highlighted the reluctance of both donor agencies and private international developers to invest in Armenia. There were many concerns voiced by the developers and donor agencies relating to the track record of GoA interference in the activities of the electric sector and its reluctance to implement necessary power market reforms suggested by international consultants such as PA Consulting.

1.4 ENERGY POLICY OF ARMENIA

The Energy Law of Armenia, as well as GoA decrees, MoUs with various parties and agreements with other countries, provide some insights on what is expected of the GoA in developing an energy policy for the country, such as:

- Energy independence, including the proposal to construct medium-sized hydropower facilities such as the Meghri project on the Araks River, an ERC-approved energy purchase price of 5 cents/kWh for a 20 MW wind power project, and a proposed natural gas pipeline connected to the Iranian pipeline system;
- Replacement of the old CHPs with new combined cycle generating units;
- Expansion of natural gas sales to residential consumers;
- Budgetary subsidies for certain entities such as hospitals, military installations, and the Yerevan Metro to guarantee energy payments.

1.5 TACIS WORK IN 2001 AND 2002

TACIS contracted with the Sogin Consulting Group to develop an energy strategy for Armenia. The consulting group cooperated with the Energy Strategy Center (an arm of the Ministry of Energy) in developing two documents on the energy strategy for Armenia. The focus of the documents was on determining what viable alternatives are available to replace the ANPP. Recommendations from the report included the construction in the next ten years of several new generating plants including three medium-sized hydroelectric plants, a combined cycle plant at the Yerevan TPP and a combined cycle plant at the Hrazdan TPP. The need for these plants was not only to replace the ANPP, but also meet an annual 5% load growth in electricity consumption. A significant amount of the load growth was to come from export sales. The first document was reviewed by the MoE and the EU, with recommendations for re-analysis. The re-analysis was completed by June 2002 finalized in a new document. The new analysis and recommendations are mostly consistent with the previous report.

The major concerns with the analysis are:

- The asserted annual load growth of 5% starting from 1999 peak and energy requirements despite the actual growth to date being negative with no prospect imminent recovery;
- The failure to consider the impact on retail electric rates and on usage from such a large construction program;
- The expectation of new markets for electricity exports in Azerbaijan and Turkey, two countries that are politically alienated from Armenia;
- The report suggested to use $50 mln. for improvement of the financial position of the energy sector. The purposes of uses of these funds were not clearly defined in the report;
- The report suggested heavy capital expenditures to complete an Iran-Armenia gas pipeline by 2008, to support massive gas-fired capacity additions due to expected high domestic power demand and exports, which are questionable;
- The report proposed construction of an 80 or 160MW co-generation plant at Yerevan although the projection of steam demand in Yerevan region was not elaborated in sufficient detail;
- The report suggested massive investments in hydropower plants (Meghri, Loriberd, Shnokh) before 2010 with no clearly defined economic criteria to choose those plants for construction;
- The report contained unworkable recommendations regarding management of the Fund for the replacement of the ANPP.

2. RESULTS FROM THE 2000 LEAST COST GENERATION PLAN AND LESSONS LEARNED

2.1 ANALYSIS PERFORMED IN THE 2000 LEAST COST GENERATION PLAN

The expected growth of domestic power system peak demand was forecasted to be 1.3% per annum. The reserve margin was estimated at 35% of the annual peak demand. The resulting capacity requirement was forecasted to rise from 1558 MW in 2000 to 2066 MW in 2015.

With the retirement of the ANPP by 2015, the results of the 2000 LCP showed that the addition of 984 MW of new generating capacity would be needed to satisfy domestic electric consumer demand. The least cost resources were an 80 MW co-generation plant in Yerevan TPP, a 400 MW Hrazdan 5 combined cycle plant, a new 388MW combined cycle plant, and 116 MW from rehabilitated hydropower plants. The least cost option was the re-powering of Unit 5 at the Hrazdan TPP to a gas-fired combined cycle generating unit. The next viable generation option selected was a new 388 MW combined cycle built on either the Hrazdan or Yerevan thermal power stations.

The report also stated that:

- Early retirement of the ANPP would not be possible without sizable rate increases for electric retail consumers;
- Many of the older thermal generating units, especially the CHPs, should be retired as soon as possible;
- A second natural gas pipeline/source would be beneficial for sector security of fuel supply and provide a potential competitive market for natural gas sales into Armenia;
- Rehabilitation of the hydropower units at the Vorotan Cascade and the Sevan-Hrazdan Cascade should be conducted as soon as possible; and,
- Large additions of hydro energy facilities would reduce dependence on foreign fuels developing energy independence for Armenia, but the economic consequences to the electric consumers would be significant.

The report was the initial least cost planning model developed for Armenia. There were some obvious shortcomings of the analysis identified in the report, namely:

- Location of new generation requires serious research and evaluation (siting analysis) of the electric transmission system, the transportation network such as railways, roads, and airports, water resources, and so forth;
- Environmental impacts should be reviewed for each generation option
- The level of demand-side management measures are somewhat related to the economic health of the country;
- The real growth of the GDP and its relationship to electric growth will require significant research and evaluation; and,
- Historical end-use data is badly needed as is forecast of end-use requirements in order to identify where and when electricity growth/reduction will occur.

2.2 RECOMMENDATIONS OF THE 2000 LCGP

Hagler Bailly, the predecessor to PA Government Service Inc., completed the 2000 LCGP with help from the MoE. The conclusions from the 2000 report included:

- Retirement of the ANPP would not be economical for the electric customers before the plant's useful life had expired;
- Load growth was most likely to be in the 1.3% per year range, and not in the 5% range predicted by the GoA;
- Construction of second natural gas pipeline/source would be beneficial for national energy security if the price of supplied gas is reduced;
- Current steam demand at the Yerevan TPP cannot support the maintenance of 4 CHP units. The report suggested that detailed study be conducted of potential industrial customers in Yerevan Region to determine the most probable steam demand level for next 10 years. This study should be made before any thermal unit can be constructed at the Yerevan CHP site;
- Two condensing units at the Yerevan CHP are old and expensive to maintain, and should be retired;
- Hrazdan TPP Block Units 1-4 should be maintained during 2000-2020. Units 1 (and possibly 2 and 3) can be refurbished to extract low-pressure steam for district heating;
- The Hrazdan CHP is subject for potential decommissioning. The report suggested that a detailed feasibility study be conducted before any work commences on the refurbishment of Units 1-3 and decommissioning of existing CHP part;
- Massive investments in the nearest future will be needed to maintain existing hydro units at the Vorotan and the Sevan-Hrazdan HPPs. New hydropower option (Meghri, Shnokh, Loriberd) is not economic because of low yearly energy production capability and high capital investment needs. However the issue of fuel security in the region may allow some hydro capacity in the future;
- The best supply-side option for Armenia would be the completion of Hrazdan Unit #5 as a natural gas fired combined cycle plant. However, the report recommended a detailed feasibility study before any actual completion and/or conversion project is started; and,
- Nuclear option is not realistic for Armenia. Coal-fired circulated fluidized bed can be considered "least-cost" among all strategic alternatives. However, further exploration of Ijevan coal deposit is recommended before any activities on the new CFB unit are commenced.

2.3 LESSONS LEARNED SINCE THE COMPLETION OF THE 2000 LCGP (2000-2002)

2.3.1 Load Forecast

The GoA's 1999 electricity demand and energy forecast (about 5% per annum) was quite optimistic while the 2000 LCP most probable load forecast was somewhat lower (about 1.3% per annum). Recent history has shown that both forecast were optimistic. The power sector has seen no growth since the 2000 LCP was developed and the loads for 2002 are projected to decrease by approximately 4.5%.

2.3.2 Lack of Data, Especially Relating to End-Use Information

As was pointed out in the 2000 LCP, the lack of end-use data hampers the ability of system planners in examining the real drivers of electricity growth and in examining the cost-effectiveness of demand-side management programs.

USAID has provided 100 data loggers (at about $1000 per logger) to the power sector for measuring the electricity flow to particular end-uses. By utilizing such data, end-use load shapes can be determined and a solid foundation of the structure of electric loads can be determined.

Unfortunately the data loggers have been stored on shelves and valuable time has been wasted by not collecting the information so badly needed in such a LCP exercise. It is imperative that the responsible parties with the distribution company put to good use the equipment provided to them so that the data can be collected and analyzed.

2.3.3 Continued Operation of the Power Stations Even with Lower Capacity Factors

The actual capacity margin in 2000 was approximately 100%, far too much excess capacity for the retail electric consumers to financially support. 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 need 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 is 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. A major concern, though, is the continual lack of funding by the GoA for the regular maintenance and the occasional capital improvements that are necessary to keep the units available when needed to cover low reserve margin periods.

The 1999 O&M study discussed in detail in the 2000 LCP report provided a base-line of expenditures (O&M, capital improvements) that were needed to maintain the generating units in good operating condition. The payments from Armenergo in the last three years not only have not covered the major capital improvements to secure the life of the plants, but the payments did not even cover basic O&M expenses. The GoA program of running power plants until catastrophic failure is very unwise and unfairly puts significant risks on electric consumers for long-term security of the power sector.

The capital improvements that were required in the years 2000, 2001 and 2002 still need to be completed for those units that are expected to continue their operation. Without the funding, the generating units will fail requiring new far-more expensive generation resources.

2.3.4 Significant Benefits from the Continued Operation of the ANPP

The 1996 general agreement between the EU and the GoA stated that the retirement of the ANPP would happen in 2004 or if and when an economic replacement of the ANPP could be found, financing made available and replacement generation construction completed. The 2000 LCP did not identify any viable economic replacement for the ANPP before its retirement in 2015. Up to this time, only the EU has proposed some financing (Euro 100 million), an amount far short from the amount that would be needed to cover the cost of replacing the ANPP with new generation resources.

There are no plans to retire the ANPP in 2004. The latest TACIS analysis, June 2002, stated that the earliest that the ANPP could be replaced is 2008. While Armenia's excess capacity allows the ANPP to shut at any time without causing power shortages, the economic consequences for Armenia would be substantial. Unless the EU is prepared to underwrite the difference in system costs without the ANPP, retirement by 2008 (or at any time before the end of the plant's useful life) seems unrealistic in light of the inability of the economy or the customers to afford the necessary rate increases.

It is time for the parties to reassess their positions and come to a concrete agreement that takes into consideration a careful transition from the ANPP as a major energy supplier to the timely decommissioning of the plant, possibly in 2015. Any such reassessment must, however, take into account the need to fund the necessary safety upgrades and maintenance at the ANPP. The present failure of the plant to collect its revenues for the electricity that it provides cannot continue without compromising both safety and reliability.

2.3.5 Siting Issues are Important in Selecting New Resources

There are several siting issues that need to be evaluated. Some of the evaluation has already begun, but the analysis should continue.

The primary issues for siting are:

- Electric transmission capability;
- Natural gas transportation capability;
- Transportation (Roads, railroads);
- Water resources; and,
- Air emissions and other environmental impacts

1. ELECTRIC TRANSMISSION CAPABILITY

The GoA has initiated discussion with Iran on providing funding for a second transmission circuit between the Shinuair substation and Ararat Substation in order to increase the amount of energy flow into and out of Iran. It is not clear whether this investment is needed given the fact the excess amount of ANPP energy in the non-winter periods can be transmitted to Iran without the new line and the likelihood that other investments have a higher priority. .

The World Bank and the JBIC have proposed the funding for rehabilitation of transmission facilities and higher voltage distribution facilities. In light of the many investments that are being proposed and the fact that consumers cannot afford to pay for all of them, a complete technical and financial analysis should be performed on the transmission system to identify existing and potential constraints and to develop a priority of investments for the HV network

2. NATURAL GAS TRANSPORTATION CAPABILITY AND LOCATION

In light of the lower forecasted natural gas requirements for fueling the thermal power plants in this LCP analysis, the requirements for expansion/rehabilitation of both the natural gas transmission lines and gas storage facilities need to be re-analyzed.

Except to the extent that diversity of supply sources and routes furthers national interests, the cost of a second source or line is the responsibility of the owner of the thermal power plant. If it is in the best interests of the power plant to secure a second line/source, then the power plant should invest into such facilities and prove to the ERC that such investment into the new line/source is prudent and to the benefit of electric rate consumers. It should be noted that due to continues transportation sabotage, it would be unlikely to find an investor to accept such responsibility. It should also be noted that the Iran-Armenia pipeline can not be economically justified, neither Armenian consumers can afford the rate impact of the full cost of this pipeline.

3. TRANSPORTATION (ROADS, RAILROADS, AIRPORT)

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

Two examples highlight the problems. First, a wind developer wanted to bring in large wind turbines into the country, but due to the size of the railroad tunnels, less efficient turbines are being proposed. The construction of a coal-fired plant will require either 1) railroad construction and/or rehabilitation, or 2) the development of a good road system between the sources of coal and the coal-fired generating plant site.

There are some possibilities to bring large pieces of equipment in large airplanes, but Zvartnots will require some rehabilitation before the large planes can land there. Once equipment arrives at Zvartnots, the ability to use the transportation infrastructure within Armenia still needs to be addressed.

4. WATER RESOURCES

The use of water resources for power plants include hydropower and thermal power 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. For proposed new power plants such as Meghri, this requirement will make it difficult to attract private investment for project development.

One aspect of the costs not reflected in this LCP is payments for water usage by power plants. It is assumed that the payments will not be large enough to affect any analysis. However, if charges for water use by power plants are not passed through to customers, they can only reduce funds available to the power plants for maintenance, salaries or profits, thereby reducing the economic viability of the hydroelectricity in Armenia.

5. AIR EMISSIONS AND OTHER ENVIRONMENTAL IMPACTS

Estimates of air emissions from natural-gas thermal power plants have been used for evaluating the benefits of demand-side management resources in this LCP. In the future, though, much consideration needs to be given to the problems of NOx from natural-gas fired resources since the problem of smog in Yerevan is growing with the increase of vehicles (smog is created by the reaction of combining: 1) NOx from power plants and vehicles; 2) volatile organic compounds (VOCs) from vehicles, paints and solvents; and 3) hot weather.

The value of non-emitting power plants is higher if the environmental externalities are calculated. The benefits to the air quality in the Hrazdan River Basin is much better if the ANPP is continued and not replaced by natural-gas fired generation in that region.

2.3.6 Decommissioning Options for the ANPP

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".[1]

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:

Decontamination – a nuclear facility is decontaminated and the site is made available for other commercial uses with no lasting radioactive residual. This option assumes that repositories are available for radioactive waste and for spent fuel.

Safe Storage – the nuclear fuel is removed from the reactor and stored on-site in dry containers until it can be moved elsewhere. The plant is kept in that condition up to sixty years until much or the radioactivity has decayed away, thereby greatly reducing the volume of radioactive waste, the potential for worker exposure and the cost of decommissioning. This option assumes that a repository for low-level waste is available to receive all radioactive material from the plant other than the spent fuel, which must be stored onsite until it can go to a repository for spent fuel.

The 2000 LCP assumed that the storage option would be selected. This option assumes that in the future Armenia will develop a low-level waste storage facility or will be able to contract for its disposal in another country.

The EU has estimated that the construction of a radioactive storage facility for the Bohunice nuclear power plant will cost EUR 1.4 billion. Spread over the seven Slovakian reactors, the cost for the storage facility is reasonable. The construction of such a facility for Armenia is unfeasible given the size of the country's budget and per capita income.

Entombment –This option entails placing the facility in a condition that will allow the remaining radioactive material to remain on site without the requirement of ever removing it totally. The radioactive parts of the plants are covered with a thick solid material (for example, concrete) to seal in radioactivity. The facility is guarded indefinitely or until a technology is found to dispose of the plant's radioactive contents economically and safely. Three small U.S. plants have adopted this technique in the 1960s, and one large plant, Maine Yankee, has analyzed the option recently and has presented the results of their analysis to the U.S. Nuclear Regulatory Commission. As with the other options, the spent fuel must be moved to another location at some point. The government of Armenia may want to give serious consideration to this option if such a use for the ANPP site is considered acceptable.

For several reasons, Armenia needs to begin realistic decommissioning planning immediately, even if decommissioning is not to occur for a decade or more.

[1] http://www.iaea.org/worldatom/Periodicals/Bulletin/Bull423/article9.pdf

Decommissioning activity, especially technical and financial planning, should begin years before the end of the life of the reactor. Indeed, decommissioning would ideally be taken into account in aspects of the original plant design. While that cannot be done for the ANPP, aspects of plant operation and upgrading may still be influenced by decommissioning considerations. And, of course, many decisions about decommissioning depend on the standards that Armenia adopts for the site after operations cease.

2.3.7.1 Decommissioning Cost Estimate

Since detailed cost estimates for ANPP decommissioning was outside of the scope of this study and this task is being currently performed by other research groups, an initial estimate for the decommissioning cost of $200 million (Y2000) is proposed for this task. More detailed analysis will verify the cost in the future. The proposed cost is based on the typical Western estimates for doing such a project soon after shutdown, as adjusted for conditions in Armenia. Estimates in the U.S. are in the $400 million range (based on per KW estimates in the $190 range), but estimates in Ukraine for decommissioning a larger VVER reactor are $172 million. Estimates from Griefswald in Germany are higher. Such an estimate does not include the cost of any necessary facilities for offsite disposal of spent fuel or of radioactive reactor parts.

Decommissioning costs (exclusive of spent fuel) will not increase greatly with continued operation. 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.

A more important variable is the decommissioning method chosen. Estimates in the U.S. have indicated that the present value of decommissioning costs can be lowered by as much as 60% if the decommissioning is postponed by some 50 years, or until much of the radiation has decayed to a point at which it no longer causes measurable worker exposure.

Unless outside donors provide a grant (as EBRD has done in Bulgaria, Lithuania and Slovakia), the costs of decommissioning must be paid for either by customers or by taxpayers. The fairest and most economically accurate method is to collect a significant proportion of the costs from the customers who are currently using the electricity. Assuming that the ANPP collects the full revenue from its sales, a charge of .005 drams/kWh would be comparable to the amounts collected for this purposes by U.S. nuclear power plants. These funds would need to be placed into an account whose only allowed purpose was to pay for decommissioning. The funds could be conservatively invested and the earnings from the investments used to help pay for the decommissioning when it occurs. Such funds, based on an electricity rate surcharge, should be put in a trust account to be used for no other purpose. The account can be assumed to grow at 7% per year in addition to the continued income from the customer charge.

In order to get LCGP non-distorted investment requirements, ANPP decommissioning cost is simply added to the derived investment cash flow. Proposed cost is considered to be constant for all decommissioning scenarios (i.e., does not account for possible decommissioning technology improvements). The decommissioning cost is free of any financing charges, interest requirements, or taxes.

2.3.7 Cost of Safety 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 recently been closed as part of the entry of those countries into the European Union. The ANPP can only operate beyond the agreed shutdown date (to say nothing of some twelve more years) if a rigorous commitment to completing necessary safety upgrades, to ongoing safety expenditures and to routine maintenance is carried out. A substantial amount of safety upgrade work remains to be done at the ANPP in order to complete the most urgent tasks. An additional safety upgrade expenditure of a few million dollars per year will be necessary once this work is complete. Until now, at least 90% of the cost of safety upgrade work has been paid for by non Armenian donor funding. Cutbacks in this outside support seem likely in the near future, leaving Armenia with the difficult choice of coming up with more money or deferring important safety work.

3. STRUCTURE OF THE 2002 LCP PROCESS AND ANALYSES PERFORMED

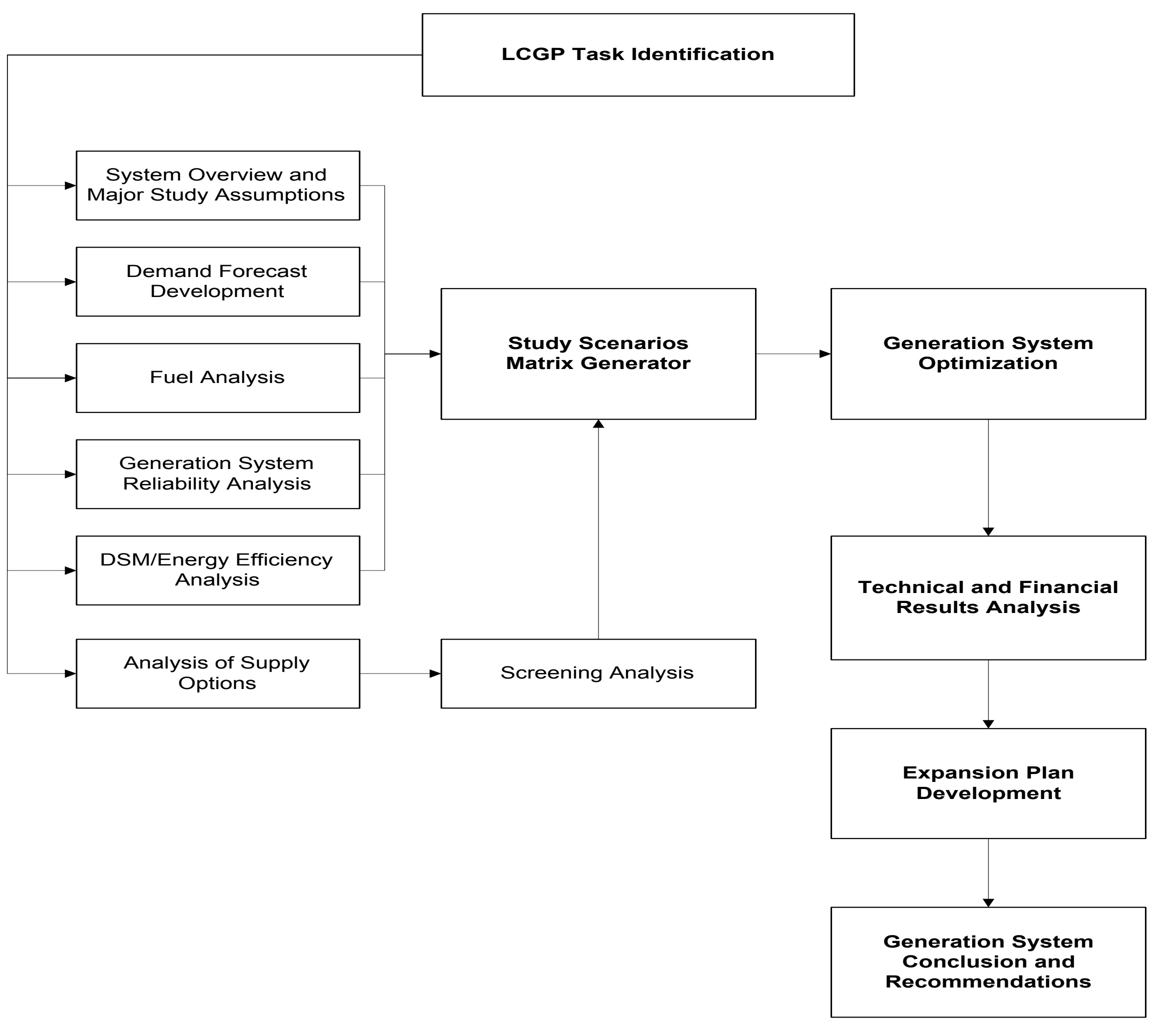
3.1 OBJECTIVES OF THE 2002 LCP

The first objective of the study was to forecast the likely demand for electricity during the next 20 years and to select an optimum mix of major capital projects for generation that would meet the country's needs for electricity through 2023. A second objective was to provide an annual investment program showing the capital requirements for the rehabilitation and expansion of the country's generation facilities. The third objective was the transfer of technology for power system planning and related methodologies to Armenian professionals engaged in the business of electricity supply.

The 2000 LCP prepared by Hagler Bailly consultants laid the initial foundation of the LCP process for Armenia and the 2002 LCP builds upon the experience from that initial LCP and from the examination of the two years that has followed that analysis.

The figure below presents a general approach to the study process.

Figure 3.1. Study Process



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 resources analysis; and,
- Supply options and screening analyses.

3.2 DATA ACQUISITION

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 studies and reports done previously by other agencies and consultants were used (including, but not limited to: Lahmeyer 1996 The Least Cost Power Sector Investment Program, 2000 Hagler Bailly LCGP Report, 1999 Hagler Bailly O&M Report, Resolutions of the ERC on Tariffs, Data from power sector companies.) This constituted a large part of the initial data set. However, in many cases the data was outdated, and contained inconsistencies and contradictions. Because of this, considerable time has been spent on validation and verification of conflicting data sources. In cases when discrepancies between reports and data obtained from the power companies occurred, the latter was used assuming that it was more recent and contained fewer mistakes.

The information on existing hydropower plants was collected mostly from previous studies and from hydropower plants (HPPs). There were studies done by European consultants, Hager Bailly Services, Harza Engineering, Burns and Roe Enterprises, and others.

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 the flows on international connections (exports and imports) was obtained from the National Dispatch Center. Information on prospective projects was obtained from the 2000 LCP efforts and updated.

3.3 FINANCIAL ASSUMPTIONS

PA used the IPM model 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 charge of capital rate.

3.3.1 Inflation

Forecast of the annual inflation rate for each of the individual year in the 20-year observation period seems almost impossible and falls beyond the scope of IPM model. Monetary policy in Armenia has never been considered for such long time horizons. Other factors influencing the inflation rate in Armenia are of low predictability, and 20-year predictions would be unworthy of any confidence.

Therefore, we will use a constant 3% annual inflation rate for the purposes of IMP model, which is the official Central Bank of Armenia estimate for the 2002 annual inflation rate.

3.3.2 Estimation of the Cost of Capital

1. BACKGROUND

The IPM model analyzes the energy sector at a macro level. The concept of the cost of capital, on the other hand, is a micro, firm specific concept. Therefore, to estimate the cost of capital (capital charge rate) for the IPM model, the energy sector is assumed to be one enterprise – Energy Company (EC). We will also assume 50%/50% debt – equity ratio for the EC.

To derive the weighted average cost of capital (WACC) for the EC, the following factors should be evaluated:

- Cost of equity, which is the return normally required by investors who invest in an energy sector, which has the same risk as the Armenian energy sector;
- Cost of debt, which is the company's cost of acquisition of funds;
- Debt-equity ratio of the company.

Since the Armenian financial markets are in early stages of development, and there is no investment ranking database on Armenian enterprises (such as EDGAR, Value Line or S&P in the US), there are no readily available benchmarks for estimation of cost of capital for the energy sector. Therefore, WACC for EC is estimated in the scenario model, which uses different sets of assumptions about input factors, described above.

2. SCENARIO ANALYSIS

i. Base Scenario

As a reference for the CE and CD, the results of negotiations of the GOA on acquisition of the Distribution Networks with the Midland Resources Holding Ltd. (MRH) and data on trading of energy bonds are used.

MRH has negotiated a 17% return on investments on its deal to acquire the Distribution Company of Armenia (Disco). Assuming the business risk in the distribution company is representative of the risk in the overall energy system and that the hypothetical energy company pays 100% of its earnings as dividends, **17%** can be used as cost of equity for our base scenario.

The GoA has recently converted a part of the obligations of the energy sector into bonds of the energy companies. These bonds are not traded in the market, they are used only for settlement purposes between the banks and the energy company. Armimpexbank, the largest dealer in these bonds, redeems energy bonds at 16% - 18% annual rate. After adjustment for the taxation effects, result for cost of debt for the EC is 18%*(1-20%)=**14.4%**.

ii. Optimistic Scenario

Keeping the CE constant, in this scenario it is assumed that the EC will be able to acquire funding from the international or regional financial markets under sovereign guarantees at LIBOR+ or other commercial basis at significantly lower rates in relation to the rates in the Armenian financial market. The Armenian energy sector has received loans from international banks under the guarantees of the Central Bank of Armenia in the past and the rates varied in the range of LIBOR +2.575% to LIBOR+6.8%, when LIBOR was 5.5%. The loans were administered by the Armenian banks. Currently, when LIBOR is 1.813%[2], the rates translate into 4.388% - 8.613%.

On the other hand, the annual 10% rate of the loan of the NIS Bank to the RA Ministry of Energy serves a reference for the lowest commercial rate from the regional markets.

For our optimistic scenario, **8.6%** will be used that is the highest rate for international loans and is closer to the regional rates. Cost of debt, therefore, is 8.6%*(1-20%)=6.88%

iii. Pessimistic Scenario

In this scenario, a CE is estimated appropriate for the domestic investors for a project in the energy sector in Armenia, which has the same risk as the EC. To estimate it, the bond-plus approach is used, assuming a 3% premium on the bonds of the company. Assuming once more that Disco risk is the same as the EC risk, result is 18%+3%=**21%** CE.

Scenario analyses are presented in the table below.

Table 3.1. Scenario Analyses

	Scenarios		
	Low	**Base**	**High**
Cost of Debt:	6.9%	14.4%	14.4%
Cost of Equity:	17.0%	17.0%	21.0%
WACC	**11.9%**	**15.7%**	**17.7%**

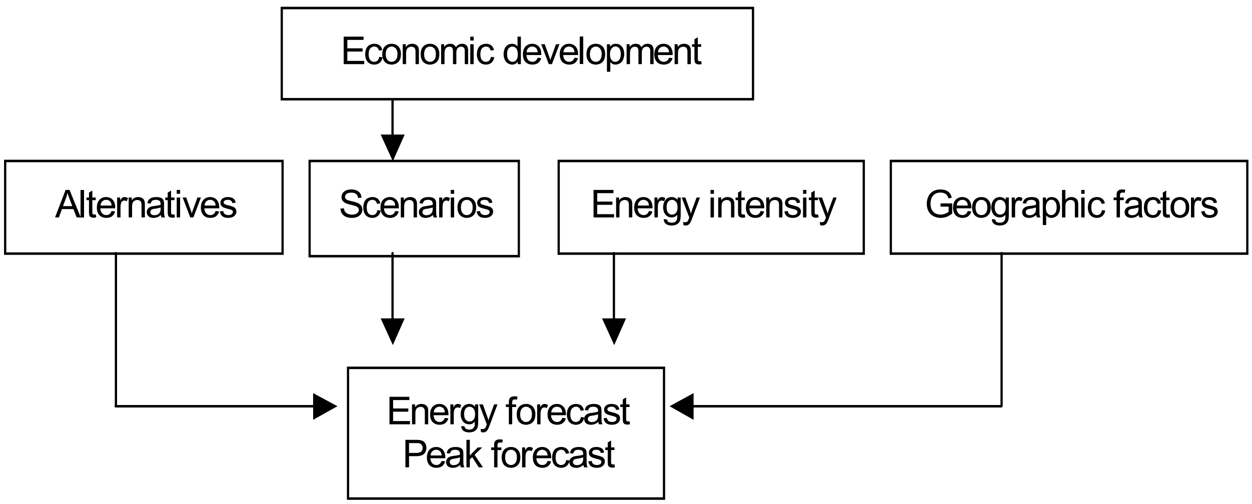
3.4 DEMAND FORECAST

The process used to develop the demand forecast for this study, along with the set of models for various segments of the market, are presented in the Figure 3.2. This process is a top-

[2] For 1 year dollar denominated loan, as of September 2002

down process where total system energy and peak load are forecasted first and then the energy forecast by individual customer load types (residential, commercial, industrial and so forth) are developed as a second phase of the load forecasting process. Only the total system energy and peaks are used in the 2002 LCP process.

Figure 3.2. System of models for projecting electricity consumption in Armenia.



Details of the load forecasting process can be found in Chapter 4 and Appendix A of this report.

3.5 SYSTEM RELIABILITY

The calculations of the reserve margin requirement were performed using the sophisticated computer programs, which employ the approach of probability convolutions for calculation of the reserve margin.

The reserve margin assumed in the 2002 LCP was 25% of annual peak load. The calculation of reserve margin in the 2000 LCP assumed that Armenia would need 35% reserve margin in the absence in operating in parallel with the Iran power network, but a 25% reserve margin if operating in parallel with the Iran power network. Given the recent commitments by both countries to continue parallel operation and to expand the transmission capability within Armenia, the 2002 LCP assumes that the Iran and Armenia power sectors will continue to operate in parallel throughout the study period.

Specific details on the calculations of the capacity reserve margin for Armenia can be found in Chapter 3 of the 2000 LCP.

3.6 FUEL ANALYSIS

Fuel analysis was focused primarily on identifying potential fuel sources for power production and forecasting its consumption and price escalation patterns. The results of analysis of fuel supply options were used as important components of input data package for modeling.

Natural gas has been identified as the primary fuel to be used by the Armenian power sector in the foreseeable future. Two major factors were considered for natural gas price forecast. The first one is based on proposition that the world trend of natural gas price may not be directly applied to the situation in Armenia. Secondly, the assumption was made that some competition is expected on the Armenian gas market due to the fact that a number of Armenia's neighboring countries have vast gas reserves.

Given the low electric load forecast, aside from security of supply stand point, the existing gas pipeline system of Armenia is more than adequate to provide natural gas during the study period regardless of the retirement date of the ANPP.

Since there was no access to detailed data concerning nuclear fuel, the information used in the current Least Cost Plan was based on official reports published by other Consultants. Coal and mazut fuels assumptions were based on recent fuel costs and estimates of fuel escalation and availability from the Armenia Coal Resource Evaluation Report prepared by Hagler Bailly (August 2000).

3.7 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. The screening process implies the determination of screening curves, which take into account capital costs, fuel costs and fixed and variable O&M costs, expressed in annualized dollars per kW against various load factors. The objective is to select the technologies with the lowest life cycle unit costs.

The generating units selected for the 2002 LCP were identical to the 2000 LCP units selected except for the elimination of Unit #5 at the Hrazdan TPP beyond 2006. The technology for the unit is becoming very old (the unit construction began in the 1980's) and the condition of the existing equipment is dependent upon careful preservation. It is very unclear whether or not any Party will maintain the equipment given that the funding by EBRD has ended and that there is no domestic need for the capacity or energy from the plant.

3.8 OPTIMIZATION PROCESS

The Wholesale Integrated Planning Model (IPM™) of 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 option characteristics to make decisions for the present.

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. In IPM™ all its modules are governed by a single main driver of the program 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 IPM™ model, as in the 2000 LCP analyses, was used in the 2002 LCP analyses to perform both dispatch and financial analysis. The goal of the model is the minimization of the present value of the total costs of the simulated power system in the entire time horizon, which includes:

- Production cost of electricity;
- Capital investments into new power plant 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;
- The minimized sum also includes 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;
- Thermal power plant's 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 dispatching (utilization) of available generating resources to meet balance conditions, as well as the commissioning of new resources in view of service-life efficiency.

The cost of decommissioning the ANPP was 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 of 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 generations will bear the cost, most likely through taxation.

3.9 INVESTMENT PLANNING

The IPM optimization modeling provided results in terms of optimized capacity and investments requirements for the time interval of 2003-2022. Optimizing for this 20-year period, instead of on short-term basis, allowed 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 NPV cost.

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

3.10 SENSITIVITY ANALYSIS

The sensitivity analysis was conducted to assess potential impacts of electricity load forecast, Armenian Nuclear Power Plant decommissioning date, 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, the Meghri hydropower project on the Araks River, as a proxy for other strategic options. The report shows the economic penalty to consumers for providing reducing fuel risk through development of generating units using domestic sources of energy.

4. DEMAND-SIDE ANALYSES

4.1 LOAD FORECASTING ANALYSIS

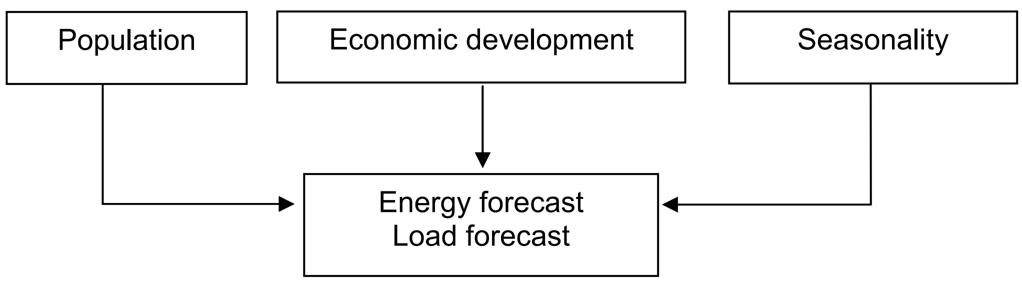
4.1.1 Introduction

This chapter summarizes the results of the energy and demand forecast, which was developed based on economic and historical factors for the years 2002 to 2022. The detailed analyses and explanations of these forecasts including the energy export and import forecasts, are presented in Appendix A of this report.

The forecasting procedures involved both the use of econometric modeling and statistical techniques.

The modules employed for these forecasts involve the combination of several models, where the outcome of some serves as an input for others. This procedure is summarized in Figure 4.1.

Figure 4.1. Structure of the Models



The scenarios used in this study include Low, Medium and High cases. To develop them the results of the previous forecast were used. The slow and high growth scenarios developed two years ago differed from the base scenario by -9% and +14% in terms of energy demand. For this study it was decided to increase the variation. Thus for the slow growth scenario the energy consumption is lower than the base case by 12%. The high growth scenario is assumed to be by 36% percent higher than the base case. By its essence, the magnitude of such substantial differences are explained by the necessity to perform sensitivity analysis. The scenarios are not based on the realistic assumptions that might come true in the future.

Appendix A contains more details about each scenario.

4.1.2 Major Results

The results for all scenarios are summarized in the Table 1 and Table 2 shown below.

Table 4.1. Energy Forecast (in GWh)

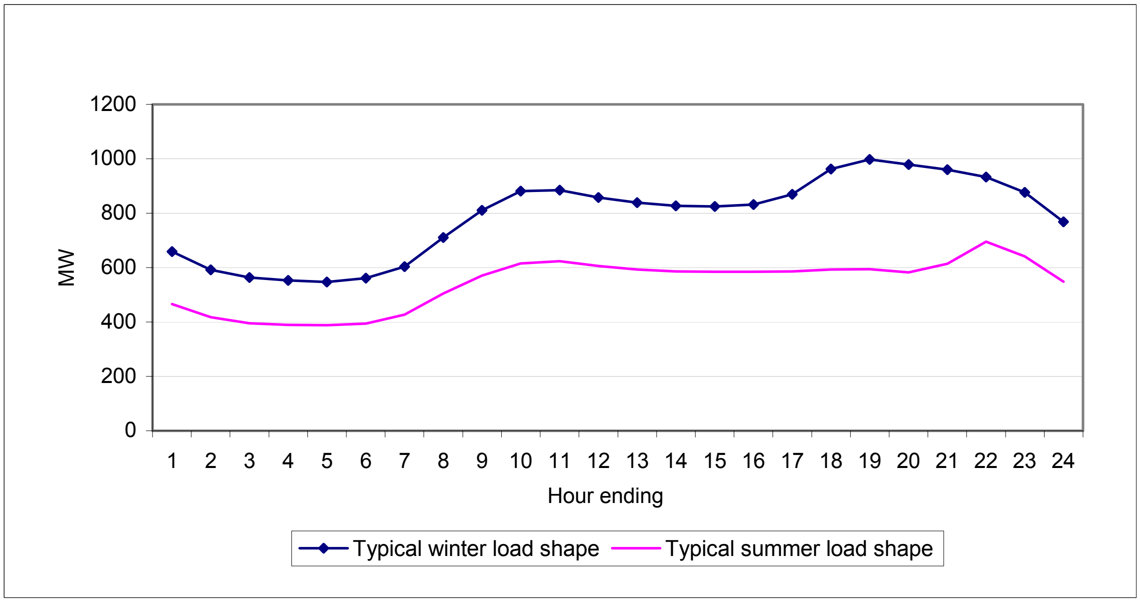
Year	Net Export (mln kWh)	Medium			High			Slow		
		Total Dome-stic Needs (mln kWh)	Net Gene-ration (mln kWh)	Gross Gene-ration (mln kWh)	Total Dome-stic Needs (mln kWh)	Net Gene-ration (mln kWh)	Gross Gene-ration (mln kWh)	Total Dome-stic Needs (mln kWh)	Net Gene-ration (mln kWh)	Gross Gene-ration (mln kWh)
2002	377	4490	5240	5623	4490	5240	5623	4490	5240	5623
2003	348	4181	4868	5223	4421	5122	5496	3587	4237	4546
2004	288	4229	4842	5196	5161	5830	6255	3734	4318	4633
2005	370	4264	4954	5315	5229	5974	6409	3762	4424	4746
2006	262	4299	4870	5225	5486	6122	6568	3789	4333	4649
2007	369	4335	5005	5370	5558	6291	6750	3817	4460	4786
2008	356	4371	5017	5383	5631	6338	6801	3846	4465	4791
2009	298	4408	4983	5346	5704	6338	6801	3875	4424	4747
2010	380	4446	5096	5467	5778	6487	6960	3904	4529	4860
2011	273	4484	5015	5381	5852	6440	6910	3933	4441	4765
2012	380	4523	5152	5527	5929	6613	7095	3967	4573	4907
2013	367	4562	5179	5557	6005	6678	7166	3999	4593	4928
2014	309	4602	5160	5536	6083	6699	7188	4032	4568	4901
2015	342	4642	5226	5548	6247	6894	7319	4066	4627	4912
2016	344	4683	5272	5596	6329	6983	7412	4100	4665	4953
2017	347	4724	5317	5645	6412	7072	7507	4133	4703	4992
2018	349	4766	5363	5694	6496	7162	7603	4167	4741	5033
2019	352	4809	5411	5744	6581	7253	7699	4202	4780	5074
2020	355	4852	5458	5794	6668	7346	7798	4237	4819	5116
2021	357	4896	5506	5845	6752	7436	7894	4272	4858	5157
2022	360	4941	5556	5898	6836	7526	7989	4308	4898	5200

Table 4.2. Peak Load Forecast (in MW)

Year	Low	Medium	High
2002	1,089	1,089	1,089
2003	968	1,088	1,196
2004	994	1,098	1,222
2005	1,000	1,106	1,235
2006	1,006	1,114	1,249
2007	1,013	1,121	1,264
2008	1,019	1,129	1,278
2009	1,025	1,138	1,293
2010	1,032	1,146	1,308
2011	1,039	1,154	1,323
2012	1,045	1,163	1,339
2013	1,052	1,171	1,354
2014	1,059	1,180	1,370
2015	1,066	1,189	1,386
2016	1,073	1,198	1,402
2017	1,080	1,207	1,419
2018	1,088	1,216	1,436
2019	1,095	1,225	1,453
2020	1,103	1,235	1,470
2021	1,110	1,244	1,487
2022	1,118	1,254	1,505
Average Annual Growth rate, %	**0.244**	**0.758**	**1.654**

Typical hourly load curves, which were derived from average hourly loads based on actual hourly dispatch data for each month of 1998-2001, were used to analyze the changes in load shapes. The analysis has revealed that no significant shifts in consumption pattern has occurred since 1998. Average hourly loads for typical summer and winter days are presented on the Figure 4.2.

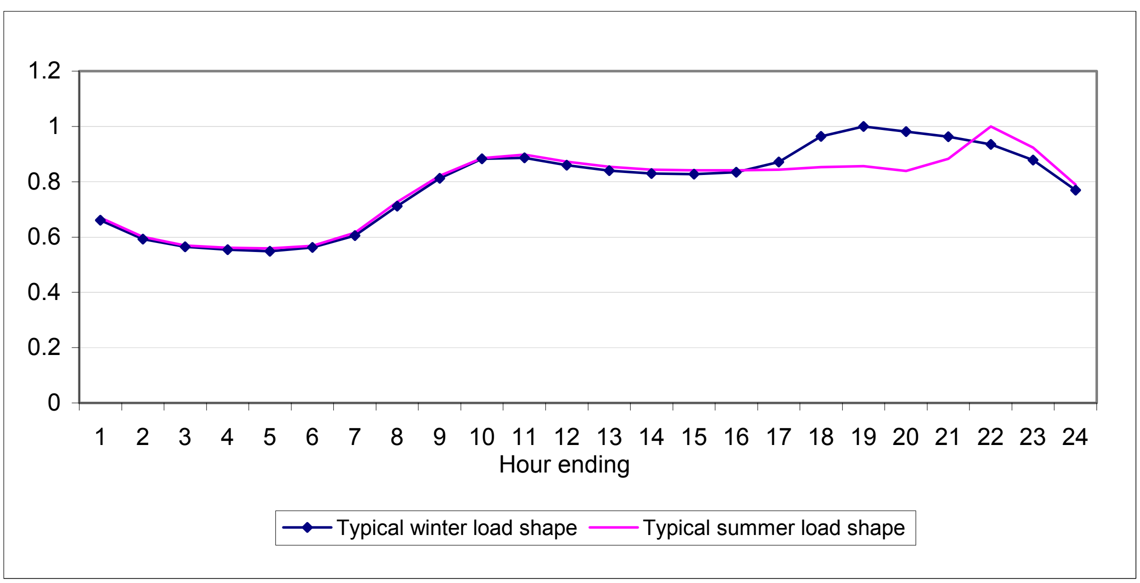
Figure 4.2. Average Hourly Loads



Average hourly loads were utilized by dividing each hourly value by the maximum daily consumption, so that the hourly values would vary between 0 and 1. Such a transformation allows for easier comparisons of load shapes, regardless of the values of maximum load.

Relative load shapes for typical summer and winter days are presented on the Figure 4.3 shown below.

Figure 4.3. Relative Load Shapes for Typical Summer and Winter Days



4.1.3 Evaluation of Historical Sales

The following two figures were developed based on the Ministry of Energy information. Figure 4.4 depicts the significant change in the structure of retail sales from 1990 to 2001 where industrial load is significantly smaller today than ten years ago as a per cent of the total sales to ultimate consumers.

Figure 4.4. Structure of Retail Sales

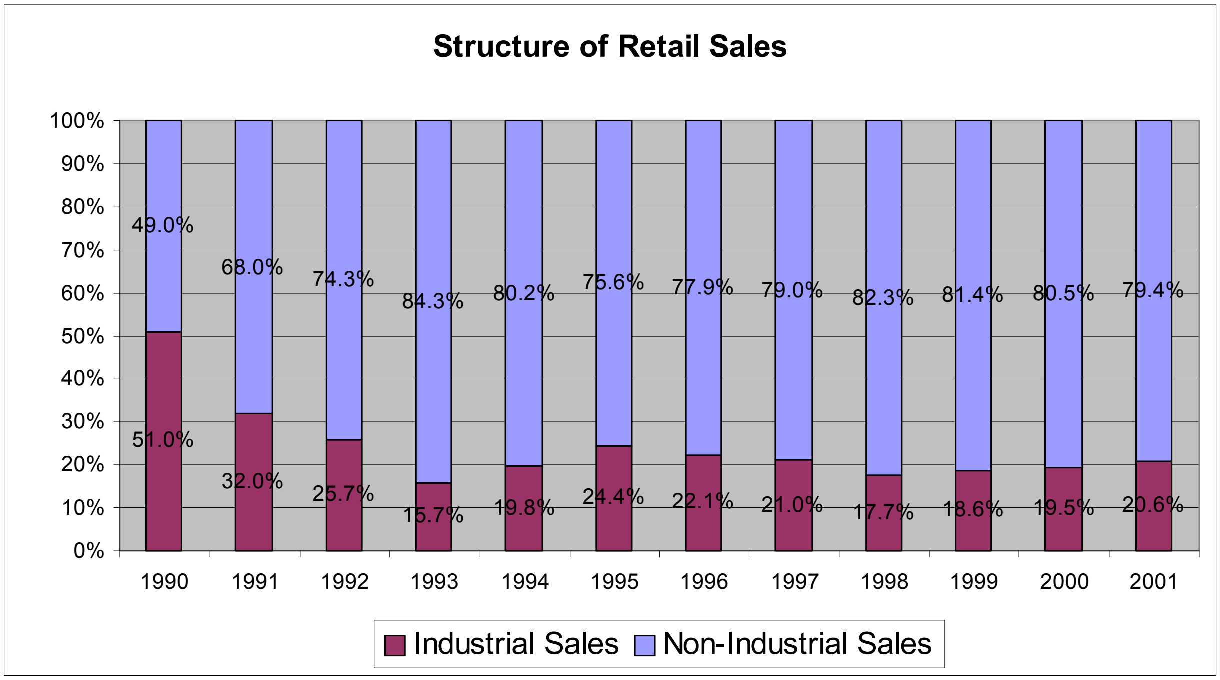
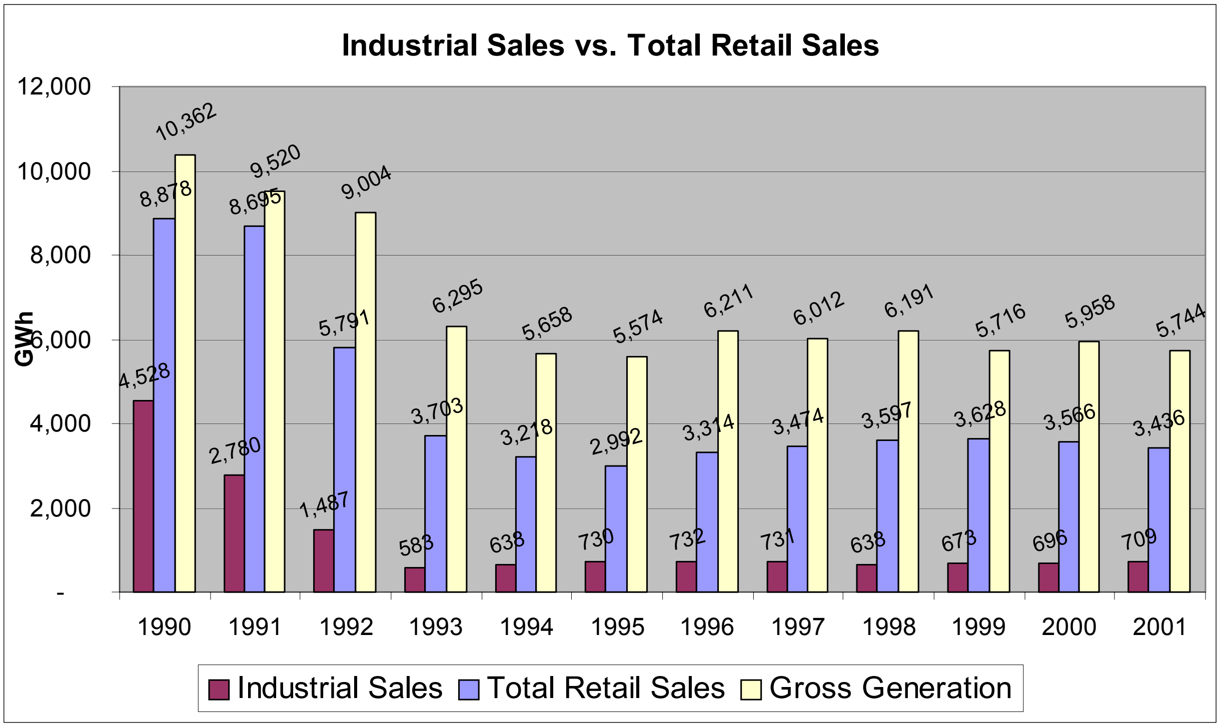


Figure 4.5 provides the sales to industrial consumers and compares those sales to the total domestic sales and total system generation from 1990 to 2001. Total sales and generation have dropped significantly since 1990. Since 1995, electric sales to industrial consumers have been about 700 GWH. Even though the GoA has reported significant GDP growth during those years, the industrial sector of electricity has remained constant. One observation from this data is that the GDP growth is not driven by industrial growth, but by non-industrial consumers.

Figure 4.5. Industrial Sales vs. Total Retail Sales



4.2 DEMAND-SIDE MANAGEMENT RESOURCES

4.2.1 Background & Situational Analysis

DSM are programs that are designed and implemented by the electric energy companies, and 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 are discussed.

Normally, the Least Cost Planning (LCP) process should consider possible DSM programs as an option to help meet future load growth, rather than just adding supply-side resources into the mix of future resources. In the past developments of LCP in Armenia, DSM programs were simply added at the end of the process, or the load forecasts were modified to reflect such programs. In those cases, there was no careful analysis of the costs, or the planned objectives (i.e. load shifting, conservation, etc.) of these DSM programs as part of the overall LCP.

From the customer's perspective, much of the Armenian energy sector has not changed substantially since PA completed the last LCP in 2000. However, a number of events have recently occurred, or are pending, that will have a large impact on the electric energy sector.

Recently, the electric distribution company was privatized. The new owner, Midland Resources, will likely not be interested in DSM programs at the same time that they are attempting to solve numerous other problems with customer service (i.e. billing and collections).

Another current activity is the development and implementation of the wholesale electricity market. While not directly affecting the consumers, the long-term impacts are expected to help keep costs optimized while maintaining, or improving, reliability of the system. As these activities proceed, the potential for the development of DSM programs to enhance the control of costs will need to be scrutinized.

As reported in the previous LCP, the physical plant infrastructure of the energy supply and distribution systems has deteriorated or collapsed because of the lack of maintenance and capital improvements. The electric power system is still operating; however, the natural gas system and district heating systems have both deteriorated considerably. Only recently has work begun on the natural gas distribution system to partially restore it for use by consumers.

A. *Electricity Sector* - The electricity sector has experienced deterioration in its generating facilities resulting in the loss of efficiencies. Additionally, fuel sources have been cut-off from some suppliers due to nonpayment. Output from the hydro facilities has dropped due to the drawdown of water from the system, particularly Lake Sevan, during the time when the nuclear facility was non-operational. Operation of the system (i.e., dispatching of generation units) has not been optimized due to a number of constraints, including the lack of accurate metering and data acquisition systems. The transmission and distribution systems are in poor shape, due to the lack of maintenance and inadequate capital expenditures. Customer metering, billing and collections are still burdened by inefficient business processes, poor equipment and inadequate financial controls. Losses, both technical and commercial, are much too high, reaching over 50% in some areas. There are current efforts to develop some small renewable resources, primarily small hydroelectric facilities and one proposal for a wind energy facility.

B. *Natural Gas* - The natural gas supplies to most of Armenia were cut by Azerbaijan following the collapse of the Soviet Union. Except for the supplies to some of the thermal generating units, only recently has the natural gas supply become available to the population in the larger cities. Unfortunately, the pipelines were not maintained in the interim period (e.g., cathodic protection was interrupted); thus, to deliver new supplies to consumers requires expenditures for rehabilitation and construction of new pipelines. Although this is now being done, it will likely be years (at least three) before natural gas is available on a widespread basis.

C. *Thermal energy supply* - Few of the district heating systems in the country are operational. Those that are operating are hugely inefficient. Estimates of the delivered efficiency of the district heating systems are as low as 20%. When the fuel supplies were curtailed, the district heating systems ceased to operate and no plans for maintaining them were adopted. Most have deteriorated to the point of being unusable even if new natural gas supplies were available. As a result, most consumers now use electric space heaters, propane, kerosene and/or wood-burning stoves to provide heat and cooking. Recently, there have been efforts to study the heating problem and there may be a few small demonstration projects on small boilers for apartment buildings and/or condominiums. If successful, these may replace some of the electric heating that is the most prevalent space-heating source used throughout the country.

4.2.2 DSM Impacts

It is not expected that DSM will have any impacts in the foreseeable future due to the recent privatization of the distribution company. However, it should be noted that the License issued to the new owners requires that they install time-of-use (TOU) meters for any customer that requests it. While this is a form of DSM, a pilot project[3] conducted by PA showed that, under the current nighttime rate design approved by the ERC, there will be not load shifting by customers due to the change to TOU metering and the nighttime tariff.

Since the previous LCP was completed, there have been several pilot projects completed and other efforts to study the energy situation and provide data for use by energy planners, consumers and the GoA. Some of this work is currently underway.

Recent pilot projects completed by PA include a weatherization pilot[4] that demonstrated the energy savings by installing, or adding, weatherization measures to a school and an apartment. In addition to the energy savings, it was demonstrated that all of the technical design, materials and labor are available by local vendors, it is not necessary to import any of these components for a project.

Another demonstration project completed by PA was a fuel substitution pilot[5]. This pilot program demonstrated the energy savings for customers switching from electric heating to natural gas space heating. Since space heating represents a large portion of residential consumers energy usage, and bills, the program demonstrated that the costs for installing gas heaters can be repaid by the savings in a reasonable time period.

USAID is currently sponsoring many demonstration projects being carried out by Advanced Engineering Associates International (AEAI). Some of these include small boiler plants with heating for one or two apartment buildings. The results of these projects, together with the GoA's recently adopted heating strategy should provide data for analyzing the future potential for small boiler plants to replace both the deteriorated district heating systems and the electric resistance heating many residential consumers are currently using.

Additionally, there may be political factors that impact the energy usage within the country. While these are obviously not DSM, the results from the perspective of the consumers may be similar to those of DSM programs.

Relative to other countries of the Newly Independent States, Armenia is better suited for the promotion of energy efficiency because the state of commercialization in the power sector is such that most consumers pay in full for the energy services they use. Recent collection figures are around 75% for the power sector, most of which is in cash. This level of commercialization has two impacts. First, the power system has already experienced substantial decreases in demand due to the conservation effect of consumers paying for the energy they use. PA has noted reductions in average electricity use as high as 60% once collection improvement strategies are put in place. Second, with consumers paying for the energy they use, consumers can benefit from the economic savings that result from energy efficiency. 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 in that it has a regulatory framework in place. Although the

---

[3] "Results of Pilot Project on Nighttime Electric Tariff", Hagler Bailly for USAID under contract No. LAG-I-00-98-00005-0, June 2000

[4] "Municipal & Residential Energy Efficiency Pilot Project", PA Consulting Group for USAID under contract No. LAG-I-00-98-00005-0, November 2000

[5] "Armenia: Results of Pilot Project on Fuel Substitution", PA Consulting Group for USAID under Contract No. LAG-I-00-98-00005-0, April 26, 2001

Energy Regulatory Commission has not addressed energy efficiency as a regulatory matter, the existence of the Commission 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.

4.2.3 DSM Potential

Although DSM programs will likely not be developed and implemented in the foreseeable future, there is potential for reducing the peak load in Armenia. A spreadsheet-based screening model[6] was developed to evaluate the potential cost-effectiveness of various energy efficiency measures, from the perspective of the end user. It also estimates the impact on emissions resulting from adoption of the new technologies. This model has produced the estimates shown in the Table 4.3 for certain DSM programs.

Table 4.3. Measures Passing the Initial Screening and Technical Potential Assuming Full Adoption (100% Market Penetration)

Description of Measure	Savings to Investment Ratio (SIR)		Estimated Reduction (Non-coincident Technical Potential in MW)
	Residential	Medium Voltage	
Weatherization	1.5	1.2	37
Central Boilers	1.6	1.1	139
Large Electric Waste Heat Pump	1.0	n.a.	38
Gas Heating, Gas Domestic Hot Water Heating and Cooking	1.0	n.a.	139
Sodium Vapor Street Lighting	1.0	n.a.	5
Compact Fluorescent Lighting	3.8	3.0	39

Assuming modest efforts to implement a program are initiated within the next six to twelve months, about 42 MW of coincident system peak coincident savings could be achieved at an estimated US $18.9 million (not including program costs such as program design, administration, and monitoring/evaluation). Annual energy savings would be approximately 203 GWh.[7]

The screening model also uses current data, obtained from the Government of Armenia, on emissions from the electric generating plants. This data was provided in kilograms per year for CO_2, SO_X and NO_X. For those measures found to be cost-effective, the estimated reductions in emissions is shown in Table 4.4 assuming that natural gas fired generation from existing thermal units is displaced.

[6] "Armenia Screening Model for Demand-Side Management & Energy Efficiency Measures", Hagler Bailly, Inc., for USAID under Contract No. LAG-I-00-98-00005-00

[7] The total non-coincident capacity savings are estimated to be 71 MW.

Table 4.4. Reduction in Emissions

Description of Measures	Annual Reduction		
	CO_2	NO_X	SO_X
Weatherization	255 Mg	193 kg	1.3 kg
Central Boilers	228 Mg	170 kg	1.2 kg
Large Electric Waste Heat Pumps	66 Mg	50 kg	0.4 kg
Gas Heating, Domestic Hot Water Heating & Cooking	124 Mg	94 kg	0.7 kg
Sodium Vapor Street Lighting	315 Mg	239 kg	1.8 kg
Compact Fluorescent Lighting	322 Mg	244 kg	1.8 kg
TOTAL	1,310 Mg	990 kg	7.2 kg

Note: Reductions are based on the assumption that natural gas fired generation is displaced.

4.2.4 Recommendations

Because of the recent privatization of the distribution company and the unknown planning strategies of the new owners, it is recommended that DSM impacts not be directly inputted into this Least Cost Plan. However, DSM should not be ignored and this chapter provides information from which future planning activities can draw on.

Based on the background and other information mentioned above, PA has the following recommendations for DSM activities as they impact energy resource planning. Due to the time needed to develop and implement new, integrated modeling techniques, the recommendations are divided into near-term strategies and long-term strategies.

1. NEAR TERM

In the near term, which is the next one to two years, the electricity resource planning process should be changed from previous methods with the following specific strategies:

a. Modify and use existing models and procedures – The models used to produce the latest least-cost plan should be modified so that they can incorporate possible DSM options into the list of resource options.

   Forecasting with DSM options embedded in the models – This means that the forecasts should include possible DSM options that reduce the future energy and peak load requirements, within the model and not a simple subtraction from the normal forecasting that is done without DSM. Several forecast scenarios (i.e. high growth, medium growth and low growth) should continue to be done. Also, other energy efficiency and conservation programs, not sponsored by the electric utilities, should be considered in the forecasting models.

b. Comparison of option costs and other factors (iterative process) – The evaluation of both supply-side and demand-side resource options should use life cycle costing that will provide an equal cost comparison of the two.

   Once the life cycle costs are determined, then a system can be devised to rank each of the options. One method is to determine the important factors that should be considered in resource planning, such as costs, reliability, environmental impacts, etc. Each of these factors should be weighted so that the total of the weighting is equal to 100. Then, each option is scored for each factor and the total is then used to rank the options.

2. LONG TERM

In the long term, there are two important actions needed. The first is a National Energy Policy, which will provide the government's overarching energy policies. The second is to implement an integrated resource planning methodology.

a. Develop and implement a National Energy Policy – This will be a national energy policy that the government will endorse and implement. It should include policies on the expansion of the natural gas distribution system, renewable energy resources, efficiency standards, energy information dissemination, and incentives for manufacturing and selling of new energy efficient equipment and appliances.
b. Implement an Integrated Resource Planning (IRP) Process – The generation planning process such as was performed in the 2000 LCGP and the 2002 LCP should be replaced by integrated resource planning process that will incorporate both supply-side and demand-side resource options into the future resource mix of the country.

3. DATABASE NEEDED FOR DEVELOPMENT

In order to develop more meaningful energy resource plans, it is necessary to begin to develop and maintain databases of information that provide important inputs to the models. While this paper addresses least cost planning, the databases mentioned here can also provide valuable information for many other energy sector needs, such as rates, customer information programs, energy efficiency programs and others. Some of these databases are described here.

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. This needs to be collected and placed into a single computerized system 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 takes a large effort, both from a human resource and an equipment viewpoint, and 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. A strong 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.)

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 needed.

f. New generation – Obviously, a database of new types of generation equipment is needed for a resource plan. The data should include the following information:

i. Initial Costs

ii. O&M Costs

iii. Operating characteristics

4. TRAINING OF PERSONNEL

Training of experts in several areas are 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.

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.

4.3 FORECAST OF ENERGY AND REQUIRED GENERATING CAPABILITY

The required reserves are between 25% and 35% above the annual peak depending upon whether or not Armenia is operating in parallel with Iran. The assumption used in the 2002 LCP is that there are good reasons for Armenia and Iran to trade in electricity and support each other's power systems, i.e., operate in parallel except when stability concerns requires disconnection of the two systems. With the assumption of parallel operation with Iran throughout the study period, it is reasonable to assume that the required capacity margin is approximately 25%.

The figures below depict several scenarios comparing required reserves to net dependable capacity of the generating units in Armenia.

Figure 4.6. ANPP retirement by 2015; Low peak forecast

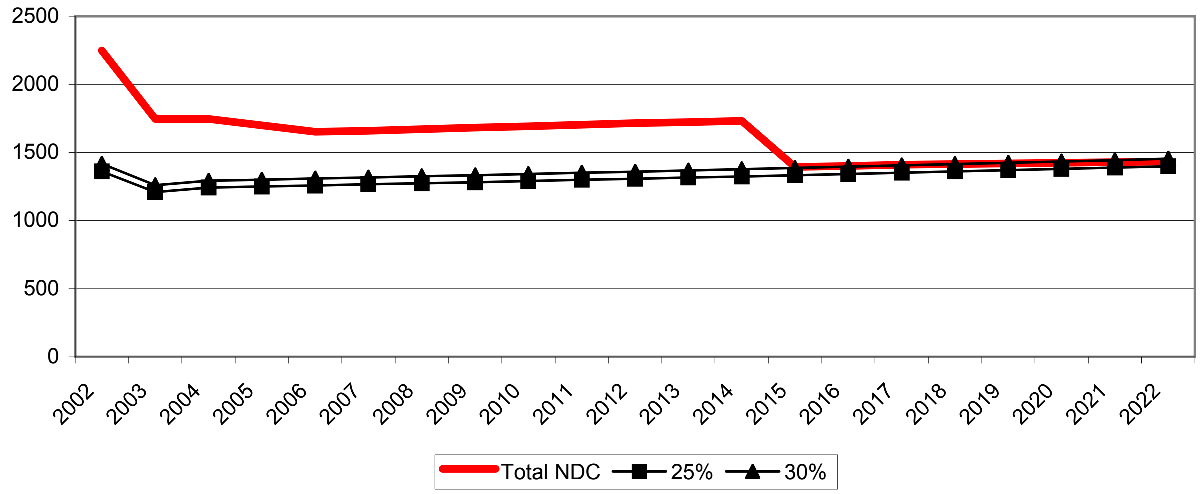


Figure 4.6 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2014, the loads will grow at the low forecast level and no new replacement capacity is added. From this standpoint, it is quite obvious that Armenia does not need any additional capacity to meet required system capacity throughout the forecast period. The observation is true even if a 30% capacity reserve is used rather than the expected level of 25%.

Figure 4.7. ANPP retirement by 2015; Medium peak forecast

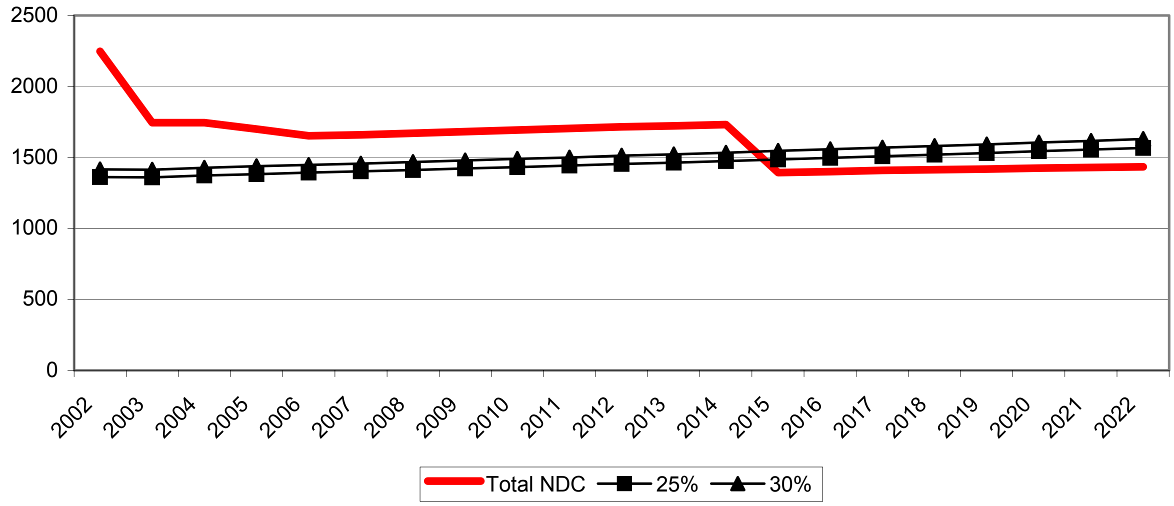


Figure 4.7 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2014, the loads will grow at the most probable forecast and no new replacement capacity is added. From this standpoint, it is quite obvious that Armenia does not need any additional capacity to meet required system capacity until the retirement of the ANPP.

Figure 4.8.. ANPP retirement by 2015; High peak forecast

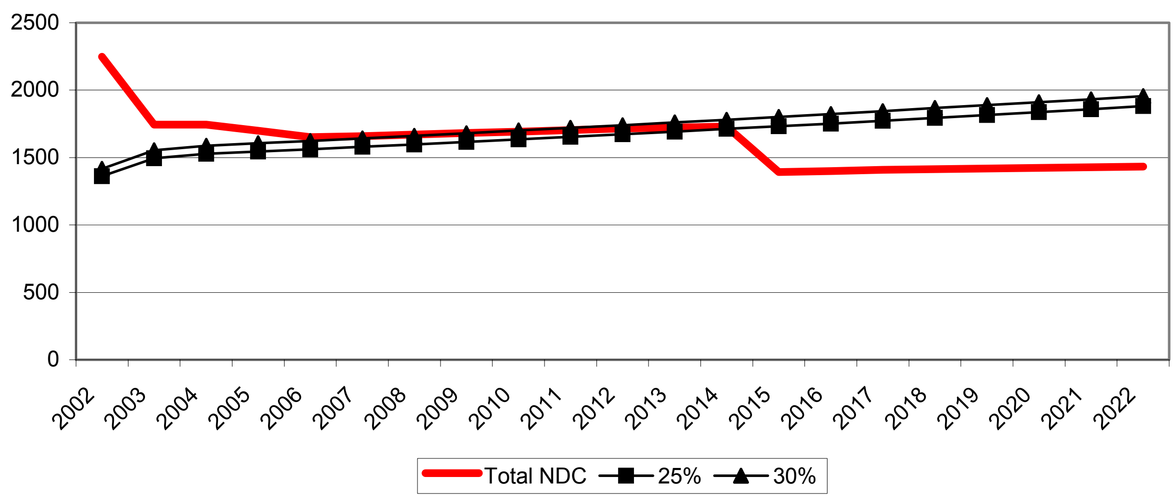


Figure 4.8 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2014, the loads will grow at the high forecast level and no new replacement capacity is added. From this standpoint, Armenia does not need any additional capacity to meet required system capacity until the retirement of the ANPP. Again, using the reserve capacity level of 25% or 30% does not impact the decision of whether or not capacity is required.

Figure 4.9. ANPP retirement by 2009; Low peak forecast

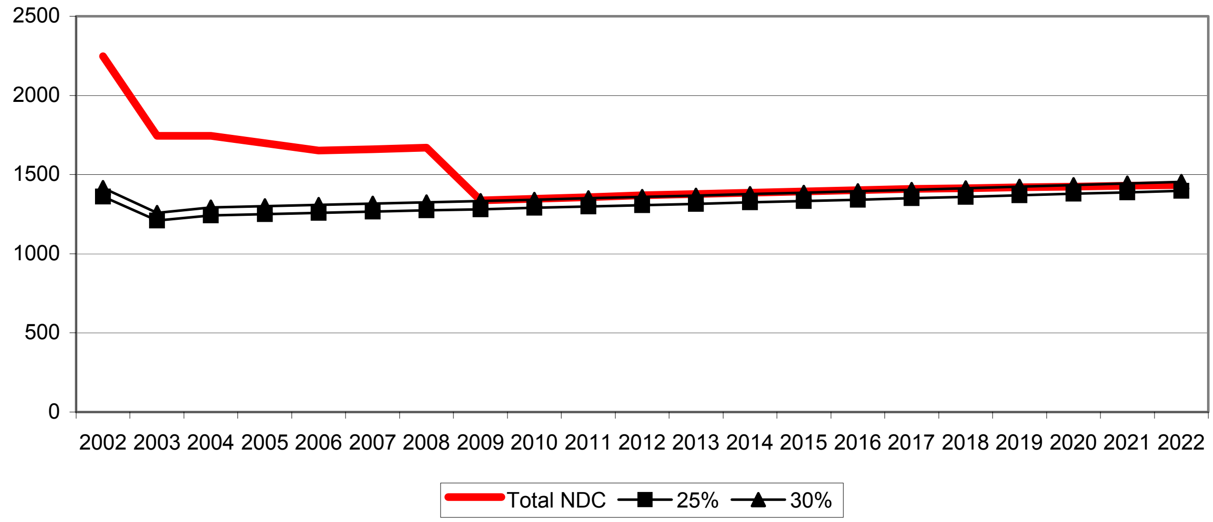


Figure 4.9 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2008, the loads will grow at the low forecast level and no new replacement capacity is added. From this standpoint, Armenia does not need any additional capacity to meet required system capacity until the retirement of the ANPP. The need for new generating capacity does not exist throughout the study period.

Figure 4.10. ANPP retirement by 2009; Medium peak forecast

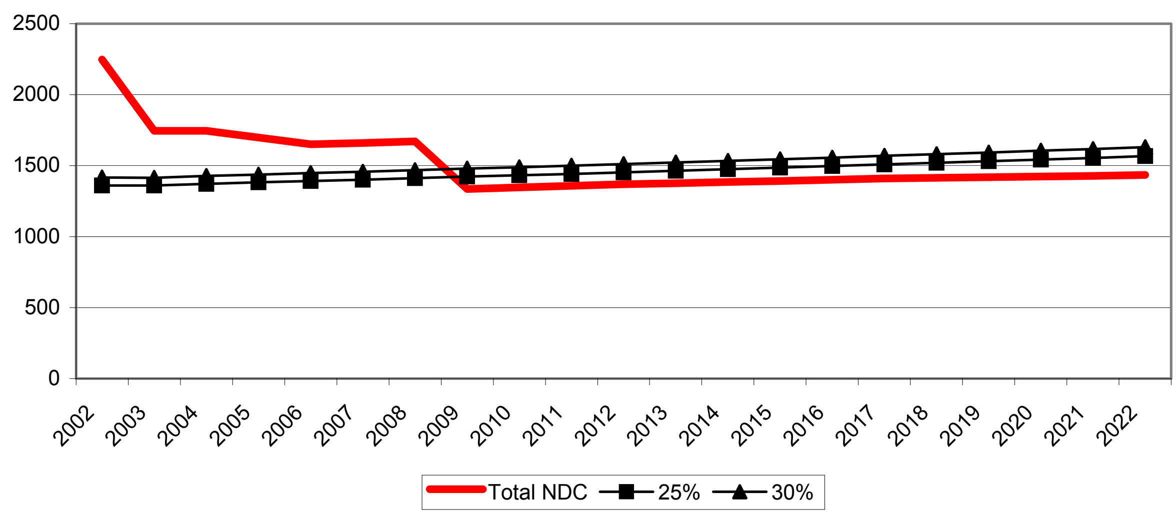


Figure 4.10 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2008, the loads will grow at the medium forecast level and no new replacement capacity is added. From this standpoint, Armenia does not need any additional capacity to meet required system capacity until the retirement of the ANPP. The amount of capacity is small and does not require any decision at this point to cover the potential shortfall.

Figure 4.11. ANPP retirement by 2009; High peak forecast

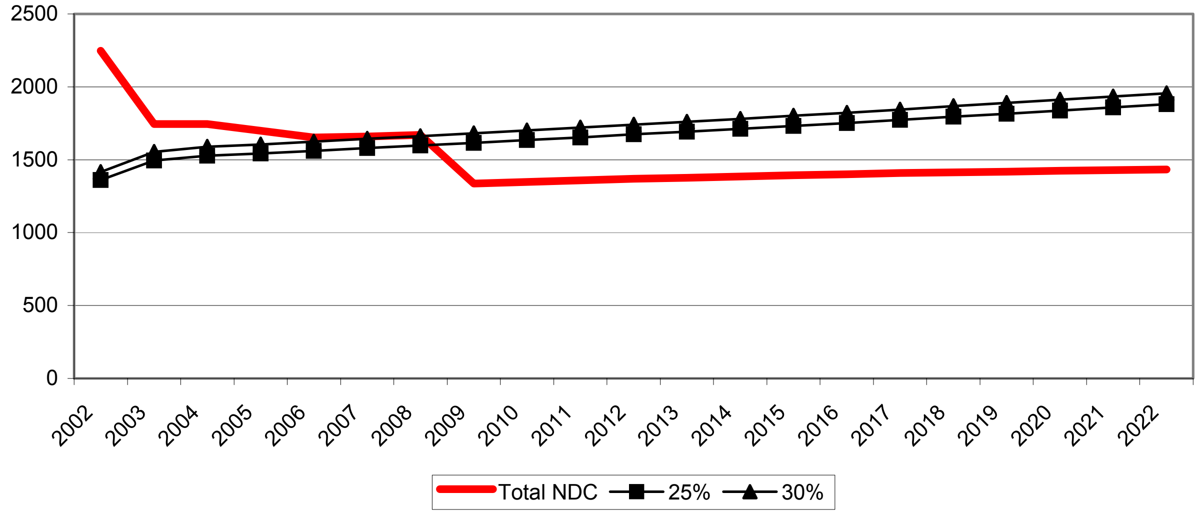


Figure 4.11 depicts the capacity situation assuming that the ANPP is retired in the fourth quarter of 2008, the loads will grow at the high forecast level and no new replacement capacity is added. From this standpoint, Armenia does not need any additional capacity to meet required system capacity until the retirement of the ANPP. The amount of capacity is not insignificant, but does not require any decision at this point to cover the potential shortfall.

The economics of adding new capacity before the retirement of the ANPP in order to reduce over all 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 later in Section 6.

5.1 EXISTING SUPPLY-SIDE RESOURCES

5.1.1 Life Extension Expenses and Capital Additions

Most plants in the power sector have exceeded thirty years of operation. As the electric load has decreased, the old thermal-powered plants have seen less and less energy output. With no significant electric load increase in the future, the operating hours of the old thermal units are forecasted to remain low. Regardless of the hours of operations, the plants will be needed for back-up of the system during low power periods and to generate occasionally during the months of higher loads (winter). The cost to maintain these generating units for this type of service is significantly lower than building any new type of generating capacity.

Operation and maintenance expenses were forecasted based on review of the 1999 O&M Study for the Power Sector, the expenditures since the report was published and with interviews with plant personnel. Since most capital improvements have been delayed over the last three years, the capital improvements were assumed to be expended in future years. One concern with the existing power plants is the continually under-funding of operation and maintenance expense by the Ministry of Energy and the condition of the plants if the Ministry continues with this pattern of under-funding. No power plant can continue operate forever in this manner (“operate until it breaks”).

Table 5.1 below provides the breakdown of operation and maintenance and capital additions for the major power plants.

Table 5.1. Breakdown of Operation and Maintenance and Capital Additions

Fuel Type	Costs	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
HYDRO	Capital improvements	6470	9416	10325	12428	13305	5651	2140	2394	795.5	1073	869
	O&M	657.8	711.6	494.7	534.6	475.2	594.4	608.2	654.9	687.4	802.2	815.7
THERMAL	Capital improvements	12500	9880	4720	0	2780	4720	400	0	2200	0	0
	O&M	10565	10882	11208	11545	11891	12248	12615	12994	13383	13785	14199
NUCLEAR	Capital improvements	0	3000	5150	5305	5464	5628	5796	0	0	0	0
	O&M	12300	12669	13049	13441	13844	14259	14687	0	0	0	0

Fuel Type	Costs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
HYDRO	Capital improvements	510	1949	1903	1681	2236	2544	2220	1810	2113	3182
	O&M	934.2	996.6	1040	1038	1091	1108	1041	1113	1228	1323
THERMAL	Capital improvements	500	0	0	0	500	0	0	0	0	0
	O&M	14624	15063	15515	15981	16460	16954	17462	17986	18526	19082
NUCLEAR	Capital improvements	0	0	0	0	0	0	0	0	0	0
	O&M	0	0	0	0	0	0	0	0	0	0

5.1.2 Net Dependable Capacity

The 2002 LCP used the net generation for thermal power plants (net dependable capacity) for determining total system capacity available to meet system capacity requirements (peak plus reserve margin). The net dependable capacity for each thermal generators was stated as average net generation (gross generation less station service).

Monthly net dependable capacity for hydro power plants (Cascades and small hydro-electric plants) was based on monthly average peak load production based on normal annual precipitation. The net dependable capacity calculated for January for the hydro-electric plants (Cascades plus the small hydro plants) was used for determining the total net dependable capacity available for meeting system capacity requirements.

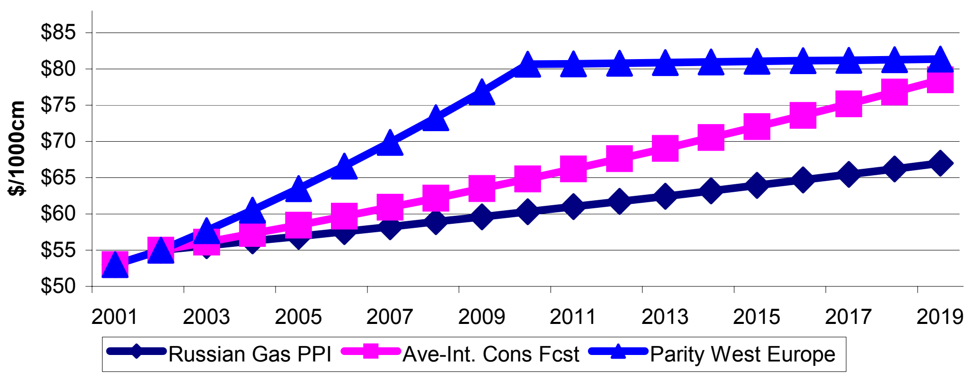
5.2 FUELS ANALYSIS AND FORECAST

The prices for natural gas, coal, nuclear fuel and mazut were developed for the twenty years of the Study. Details of the fuel price forecasts can be found in Appendix B. In particular interest for Armenia are the forecast prices for natural gas and nuclear.

Nuclear fuel prices were forecasted to stay constant in dollar terms from the 2002 nuclear fuel price. The price of nuclear fuel has not shown any indication in the past of increasing and there is no information available on the cost structure of producing nuclear fuel by the Russian entity DVEL for the ANPP.

The price of natural gas is a major factor in determining the cost of purchase power and represents the single largest cost item included in retail electric rates. Figure 5.1 below provides the forecast of natural gas prices for 2001 through 2020, for low, expected and high scenarios.

Figure 5.1. Scenario Analysis of the Border Price for Gas in Armenia



5.3 THE TEN PERCENT RULE

Electric system planners use a rule of thumb when planning for new resources that: "No one generating unit should exceed 10% of the system peak." For example, Armenia, with electricity peak load of 1,100 MW, should not construct a new generating facility with a net capacity rating greater than 110 MW.

The real impacts for not following this rule of thumb have been exposed over many years of bad experiences by power utility managers and consumers that had a single large generating unit constructed and operated on their electric systems. The impacts are significant and ignoring this rule can cause adverse effects on the electricity service reliability and electricity rates for consumers.

The four reasons not to exceed 10% of system peak in any one generating unit 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 the large generating unit out of dispatch; and,
2) The risks, both to the finances of the sector as well as to the security of the country, related to a pre-mature retirement or an extraordinarily long outage of the large generating unit.
3) The rate impacts caused by the inclusion of the large generating unit into rate base when the unit is commissioned;
4) The rate impacts caused by the inclusion of replacement power (either expensive purchased power or large investment for new units) when the unit is retired.

The Armenian power sector has or will experience each and every one of these impacts.

5.3.1 Spinning Reserve Impacts

The standards for spinning reserve require that the largest possible outage condition (the so-called first contingency or N-1 occurrence) state the power system must be able to recover fully from the 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 the large unit. In many instances, lower cost generators are backed down in order to obtain the spinning reserve, thus increasing the cost of dispatch. Also, if the size of the unit is large, there is a strong possibility that the system can not provide enough spinning reserve, thereby creating the situation that the standards are violated (firm customers are disconnected) when the large unit suddenly goes off-line. Both these conditions are actually worse when the system load is lower and less amount of generating units are on-line and therefore unavailable to provide spinning reserve.

5.3.2 Exposure to Outages or Pre-Mature Retirement

System planners are trained to perform “what if” analyses to examine the risks to consumers of certain future events. Two events related to large generating units that create a risk for consumers is the sudden shutdown of a power plant for

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

These events can have adverse effects on the system power costs (and therefore retail rates) and on reliability of the system (supply of power to consumers). Though any low energy cost generating unit can create such risks, operating smaller generating units mitigates these exposures. Without having prior notice of an event by the decisions makers (which is normal with these types of events), the system may not be able to find replacement power or will have to pay a large premium for replacement power until a long-term replacement power until a long-term solution is found. If the generating unit sizes are kept small, the impacts are kept small and the risks to the consumers are minimized.

System planners are forced to recognize the system that exists and must prepare contingency plans for such possible events. One recommendation by the planners would be to increase the level of required system capacity (peak load plus reserves) in order to insure that the system would have enough capacity to cover such events. Such increased capacity reserves will require additional costs to maintain the capacity in case such events may occur. The larger the generating unit, the larger the system capacity requirements and therefore, the larger the costs to be included in retail tariffs to maintain such capacity

5.3.3 Rate Impacts after Commissioning

Introducing a large new unit will increase retail tariffs for electric consumers with 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 puts 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. (To some extent, though, the new technology may lower energy costs due to lower heat rates.)

5.3.4 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 hole to be filled, especially a unit that provides low-cost energy and is fully depreciated. 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.

5.4 SITE ANALYSIS FOR FUTURE RESOURCES

As was described in Section 2.3.5 above, new resources must be evaluated both for their direct costs and for non-direct cost factors. The non-direct cost factors include environmental impacts (land, air, and water), access to fuel transportation systems and access to the electric networks. A process that uses these other factors in deciding whether or not the generation technologies are potential resources for Armenia must be developed. A database on this information has been created by the System Planning Department of Armenergo and work continues on obtaining all the information needed for all these factors. Once the data is complete, the use of these factors in determining the viability of new resource technologies can be used along with the direct cost factors.

5.5 NEW SUPPLY TECHNOLOGIES

Details of potential new supply technologies can be found in the 2000 LCGP, Section 8, Expansion Options. For the 2002 LCP, a few technologies were re-analyzed to see if they should be included in the list of viable potential technologies for Armenia. These technologies are described below.

5.5.1 Nuclear Options

Though some building of old technologies continues, nuclear technologies with advanced safety systems are still on the drawing board. Some recent proposals for these “passively safe” nuclear designs are in the range of 110 to 300 MW. Older technologies still under construction range from 600 to 1000 MW. The installed costs of the new nuclear technologies are projected to range from $1000/kW to $2,000/kW. Armenia's small power demand can not properly handle generating units greater than 250 MW (the spinning reserve requirement of the equivalent of the largest contingency is frequently violated). As the new passively safe nuclear technologies come closer to development later in this decade, a re-assessment should be made as to their viability for Armenia.

5.5.2 Renewable Resources

Hydro – In Armenia, the using pumps in reverse for turbines is a method to greatly reduce costs of the facilities, but there is counter effect of decreasing efficiency. Given the need to keep power costs down, the use of pumps as turbines has been very beneficial to the retail electric consumers. The decision to use the pumps should be left to the developers. If the use of regular turbines can provide benefits, then the developer can decide not to use pumps. The 2002 LCP assumes that another 73 MW of hydroelectric power net dependable capacity will be constructed using pumps for turbines (i.e., lower cost production).

Wind - Wind technology has matured from the testing stage into mass production. There are many varieties of wind technologies and capacity sizes. Common capacity sizes range from 50 kW to 1 MW. One developer has received approval of an initial year tariff of 5 cents/kWh with promises by the ERC to adjust the tariff based on a cost of service evaluation. A recent study completed by NREL for Armenia concludes that more than 4000 MW of economic wind power exists in Armenia.

5.4.3 Fuel Cells

This technology is been studied and tested for more than two decades, though it still is not being mass-produced. The units are small, starting at 10 kW, but are modular and can be built to any size. Carbon-based fuels are fed into the units, with electricity, hot water and very small emissions are output. Car manufacturers are exploring the use of fuel cells in 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.

5.4.6 Clean Coal

Clean-coal technologies continue to improve on costs. A detailed study of the coal capabilities and its use in clean-coal plants needs further analysis. There are still concerns about the fuel quality available 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 phosphate, to be shipped into the plant and later buried, thus requiring significant rail transportation capabilities and supply of phosphate for flue-gas desulphurization. The use of clean-coal technology will require an integrated study of the technology, the availability of cost-effective coal, the availability of phosphates in the region, and the ability of the transportation system (trucking, rail) to handle the needs for transporting the coal.

6. *ECONOMIC AND FINANCIAL ANALYSIS*

6.1 INTRODUCTION

The 2002 LCP results are based on scenario analysis. Ten scenarios were analyzed and shown below in summary form.

CASE 1. BASE CASE/SCENARIO
ANPP Retirement in 2009 / Medium Demand / WACC / Fuel Price Forecasts
CASE 2. ALTERNATIVE SCENARIO
ANPP Retirement in 2015 /Medium Demand / WACC / Fuel Price Forecasts
CASE 3. HIGH DEMAND FORECAST
ANPP Retirement in 2009 / Medium WACC / Fuel Price / High Demand Forecasts
CASE 4. LOW DEMAND FORECAST
ANPP Retirement in 2009/Medium WACC / Fuel Price/Low Demand Forecasts
CASE 5. HIGH FUEL PRICE FORECAST
ANPP Retirement in 2009/Medium WACC / Demand / High Fuel Price Forecasts
CASE 6. LOW FUEL PRICE FORECAST
ANPP Retirement in 2009/Medium WACC / Demand / Low Fuel Price Forecasts
CASE 7. HIGH DISCOUNT RATE FORECAST
ANPP Retirement in 2009 / Medium Demand / Fuel Price Forecasts/ High WACC Forecast
CASE 8. LOW DISCOUNT RATE FORECAST
ANPP Retirement in 2009 / Medium Demand / Fuel Price Forecasts/ Low WACC Forecast
CASE 9. 30% RESERVE MARGIN – RELIABILITY
ANPP Retirement in 2009 / Medium Demand / WACC / Fuel Price Forecasts / 30% Reserve requirement
CASE 10. MEGRI HPP ENFORCEMENT - STRATEGIC
ANPP Retirement in 2009 / Medium Demand / WACC / Fuel Price Forecasts /Meghri HPP Enforcement

Variables to be analyzed for the future were chosen as those variables that would have a meaningful impact on purchase power costs. These variables are:

- Electric consumption growth (peak loads and energy consumed);
- Fuel prices, especially related to natural gas;
- Weighted average cost of capital; and,
- Capacity reserve margin.

The base case or base scenario was developed assuming expected future values for electric demand, weighted average cost of capital (WACC), capacity reserve margin, and fuel prices. The base case assumed that the ANPP would retire in the fourth quarter of 2008.

An alternative base case was examined that kept all assumptions the same except that the ANPP was retired in the fourth quarter of 2014.

The table above shows the ten cases with the varying assumption. The last case, Meghri HPP Enforcement – Strategic, was analyzed to determine the additional cost for electric consumers to decrease natural gas dependence by building domestic renewable resources.

Detailed summary results of each case/scenario analysis can be found in Appendix C. Summaries of the analysis for the base case, the alternative base case and the Meghri HPP Enforcement case are presented in Sections 6.2 through 6.5 below. Section 6.6 provides a table of the results for the other cases in net present value costs.

6.2 BASE CASE

6.2.1 Capacity Additions and Changes (MWNet) by Plant Type

The base case or base scenario is the scenario for this 2002 LCP includes the expected future values for the variables analyzed in this study. Expected load growth, expected natural gas prices, expected weighted cost of capital, and a 25% capacity reserve margin were used in the base case.

Table 6.1 provides the changes in generation capacity for the base case. For displacing the ANPP capacity after its assumed retirement in late 2008, three natural-gas fired gas turbines were needed. To cover electric load growth during the study period, an additional gas turbine was needed in 2015.

Table 6.1. Capacity Additions and Retirements for the Base Case

Year	2003	2006	2007	2008	2009	2016
Gas Other			75 GTS	75 GTS	75 GTS	75 GTS
Nuclear					-346 ANPP Unit 2	
Gas CHP	-2*44 Yerevan CHP 2&4 -2*92 Hrazdan CHP 3&4	-46 Hrazdan CHP 2	-46 Hrazdan CHP 1			
Coal						
CombCycle						
Hydro						
Total	**-272**	**-46**	**29**	**75**	**-271**	**75**

Note: (+) - additions
(-) - retirements

6.2.2 Generation and Capacity Mix

Due to the low forecasted electric energy and peak load growth, no large generating units are required on the system. The retirement of the nuclear power plant is the major factor driving the need for new capacity. As was shown in the 2000 LCGP, though, sometimes the savings in fuel costs from the installation of new efficient generators can reduce the overall cost of generation. This can be shown by the gas turbine coming on-line in the year 2007 instead of 2009 when the capacity was required.

Figures 6.1 and 6.2 below provide the generation energy supply mix and capacity mix annually for the study period for the base case.

Figure 6.1. Energy Supply by Fuel Type for the Base Case

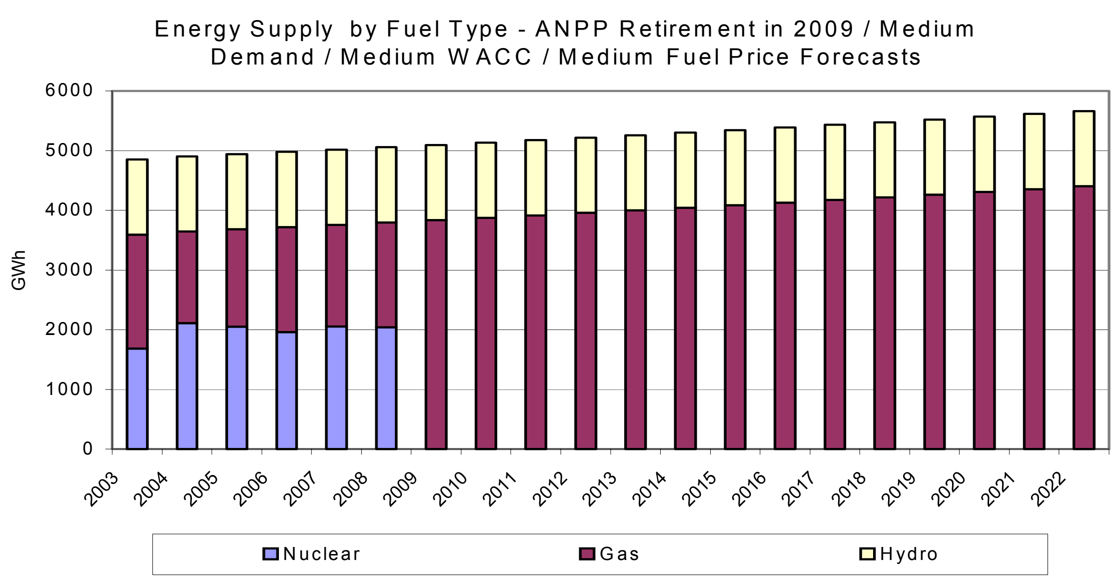
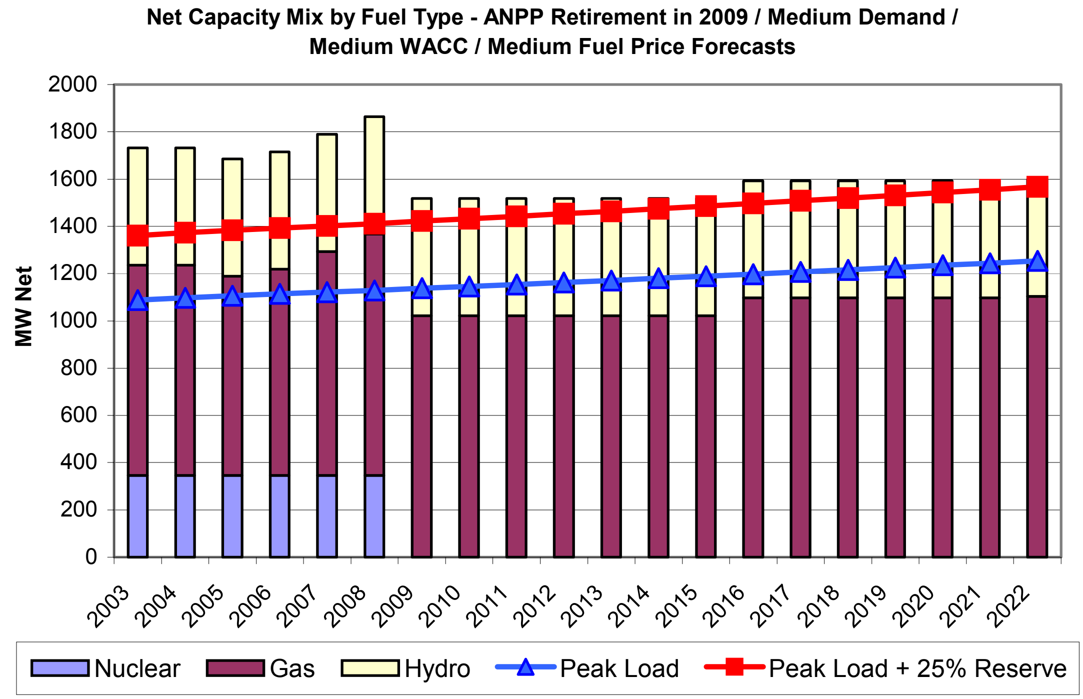


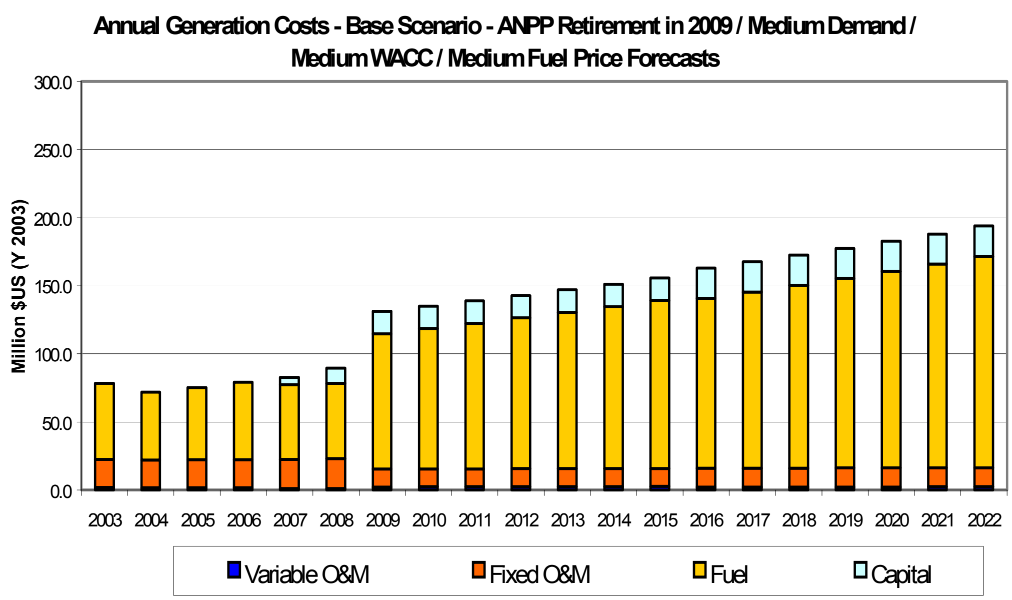
Figure 6.2. Generating Capacity Mix by Fuel Type for the Base Case



6.2.3 Annual Generation Costs

Figure 6.3 depicts the annual costs in 2003 dollars for generation to meet energy requirements of the system. In 2009 the jump in cost is attributable to the retirement of the ANPP at the end of 2008.

Figure 6.3. Annual Costs ($2003) for Generation for the Base Case



6.3 ALTERNATIVE SCENARIO – ANPP RETIREMENT IN 2015

An alternative to the base case was examined. This alternative case kept all variables constant, but extended the life of the ANPP to the end of 2014. The major change in the analysis is the delay in building new capacity and the significant reduction from the base case in the reliance of the country on natural gas.

Table 6.2. Capacity Additions and Retirements for the Alternative Base Case (MW)

Year	2003	2006	2007	2009	2014	2015	2016
Gas Other				75 Gas Turbine	75 Gas Turbine	75 Gas Turbine	75 Gas Turbine
Nuclear						-346 ANPP Unit 2	
Gas CHP	-2*44 Yerevan CHP 2&4 -2*92 Hrazdan CHP 3&4	-46 Hrazdan CHP 2	-46 Hrazdan CHP 1				
Coal							
CombCycle							
Hydro							
Total	**-272**	**-46**	**-46**	**75**	**75**	**-271**	**75**

Note: (+) - additions
(-) - retirements

Figure 6.4. Generation Capacity Mix for the Alternative Case

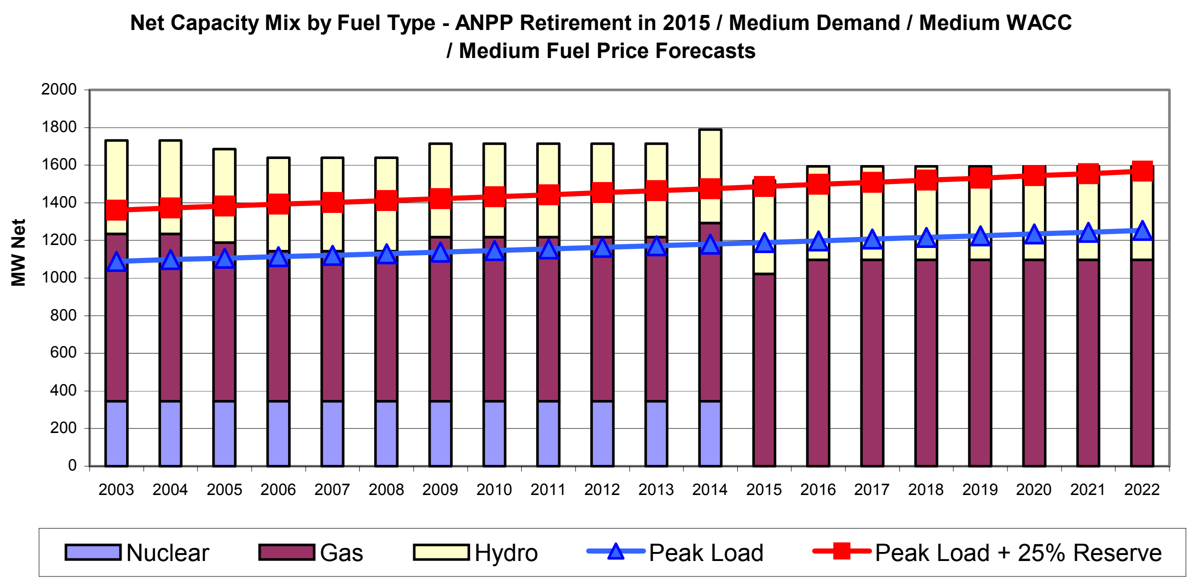


Figure 6.5. Generation Energy Mix for the Alternative Case

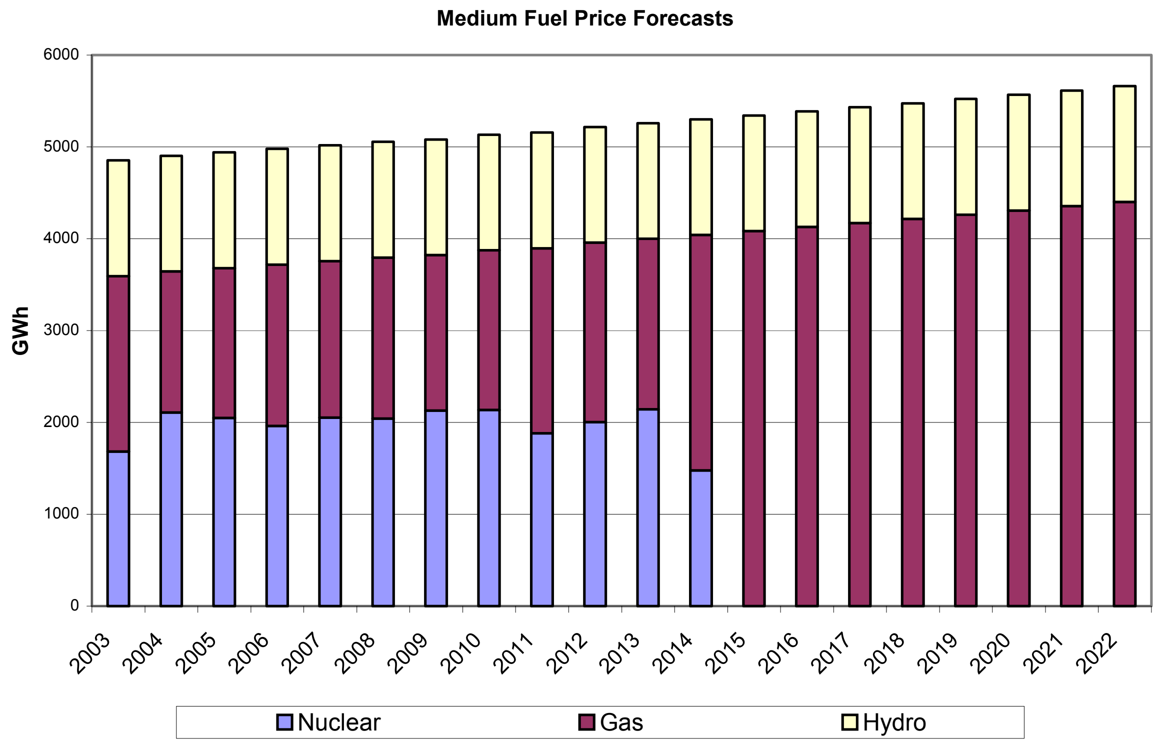
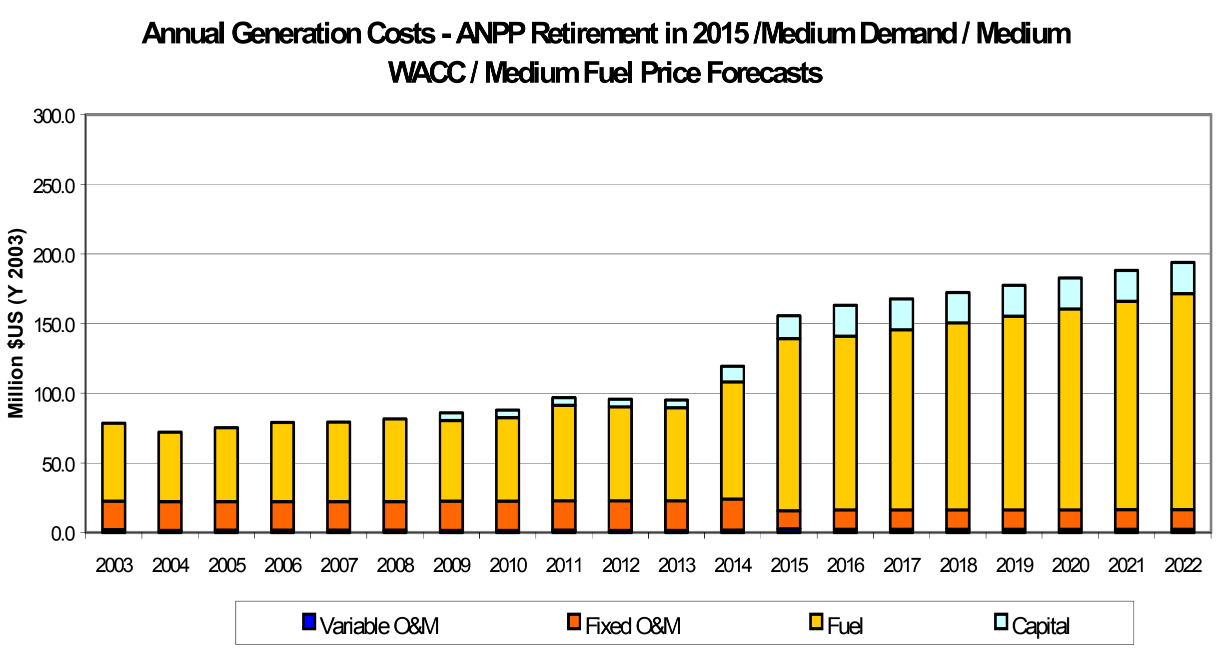


Figure 6.6. Annual Generation Costs for the Alternative Case



The figures above highlight the positive impact of delaying the retirement of the ANPP. The delay required investments during the next ten years is very positive for the population that will face increased tariffs in other sectors to cover required investments for the rehabilitation of those sectors. Even within the power sector, significant investment is required for rehabilitation of the transmission and distribution networks and the costs of those investments will require significant increases in retail electric consumer tariffs.

In any case, the Energy Commission will face a time when the sudden increase of retail tariffs will occur when the ANPP retires. Some consideration should be made as to the possible methods of modifying the sudden increase (shock) to consumers of higher retail rates caused by the retirement of the ANPP.

6.4 STRATEGIC SCENARIO – MEGRI HPP ENFORCEMENT

The Meghri HPP Enforcement Case was analyzed to determine what would be the additional costs to consumers for the potential domestic generation. The IPM model did not select any of the domestic generation options due to the higher investment costs. These options included the three medium-sized hydro plants (Meghri, Shnokh and Loriberd) and a coal-fired power plant. The Meghri power plant was selected as a proxy for the other domestic options. By requiring the IPM program to use the resource, the additional cost above the base case and the alternative base case could be determined. The results are shown in Table 6.3 and Figures 6.7 through 6.9 below.

Table 6.3. Capacity Additions and Retirements for the Meghri HPP Enforcement Case (MW)

Year	**2003**	**2006**	**2007**	**2008**	**2009**	**2014**	**2021**
Gas Other				75 Gas Turbine	75 Gas Turbine	75 Gas Turbine	75 Gas Turbine
Nuclear					-346 ANPP Unit 2		
Gas CHP	-2*44 Yerevan CHP 2&4 -2*92 Hrazdan CHP 3&4	-46 Hrazdan CHP 2	-46 Hrazdan CHP 1				
Coal							
CC							
Hydro				85 Meghri HPP			
Total	**-272**	**-46**	**-46**	**160**	**-271**	**75**	**75**

Note: (+) - additions
(-) - retirements

Figure 6.7. Generation Energy Supply for the Meghri HPP Enforcement Case

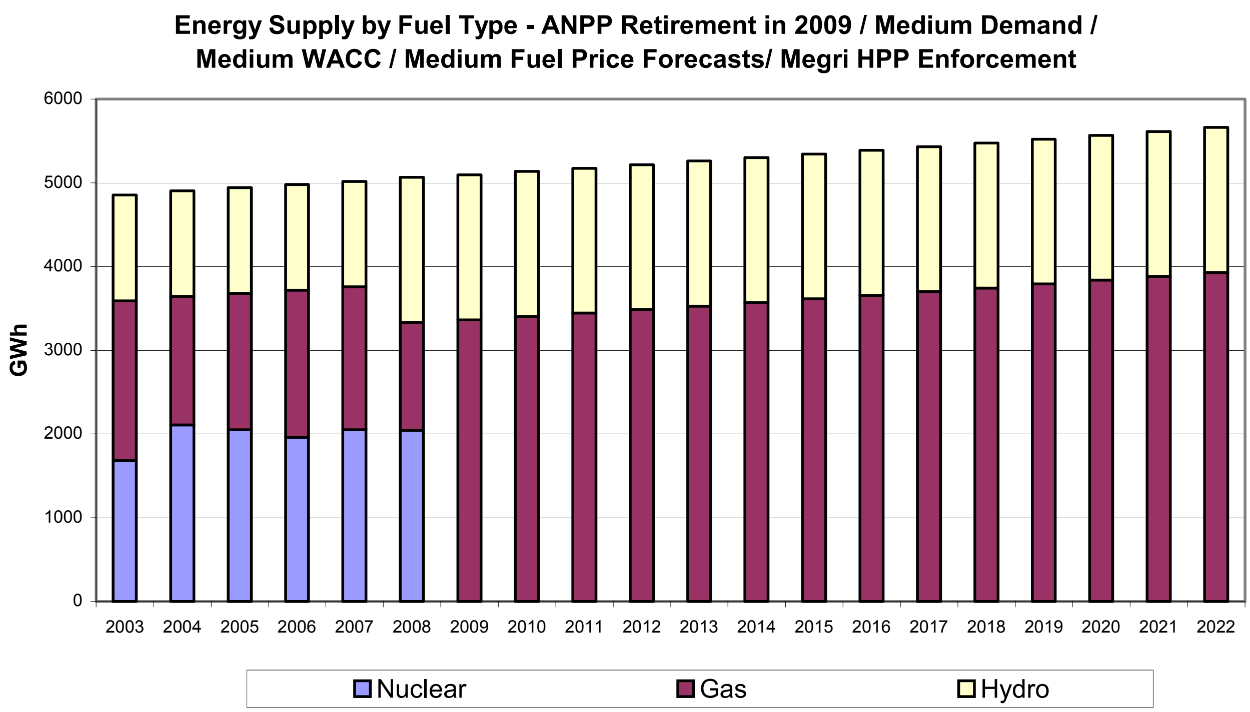


Figure 6.8. Generation Capacity by Fuel Type for the Meghri HPP Enforcement Case

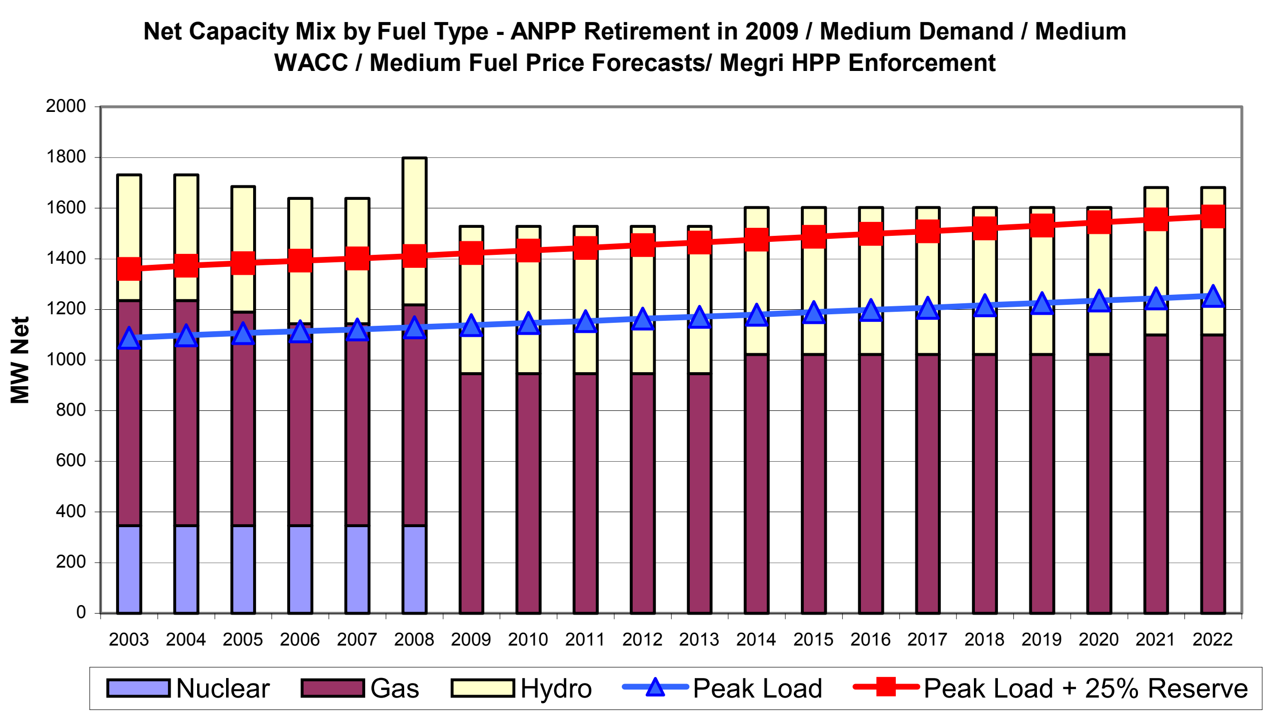
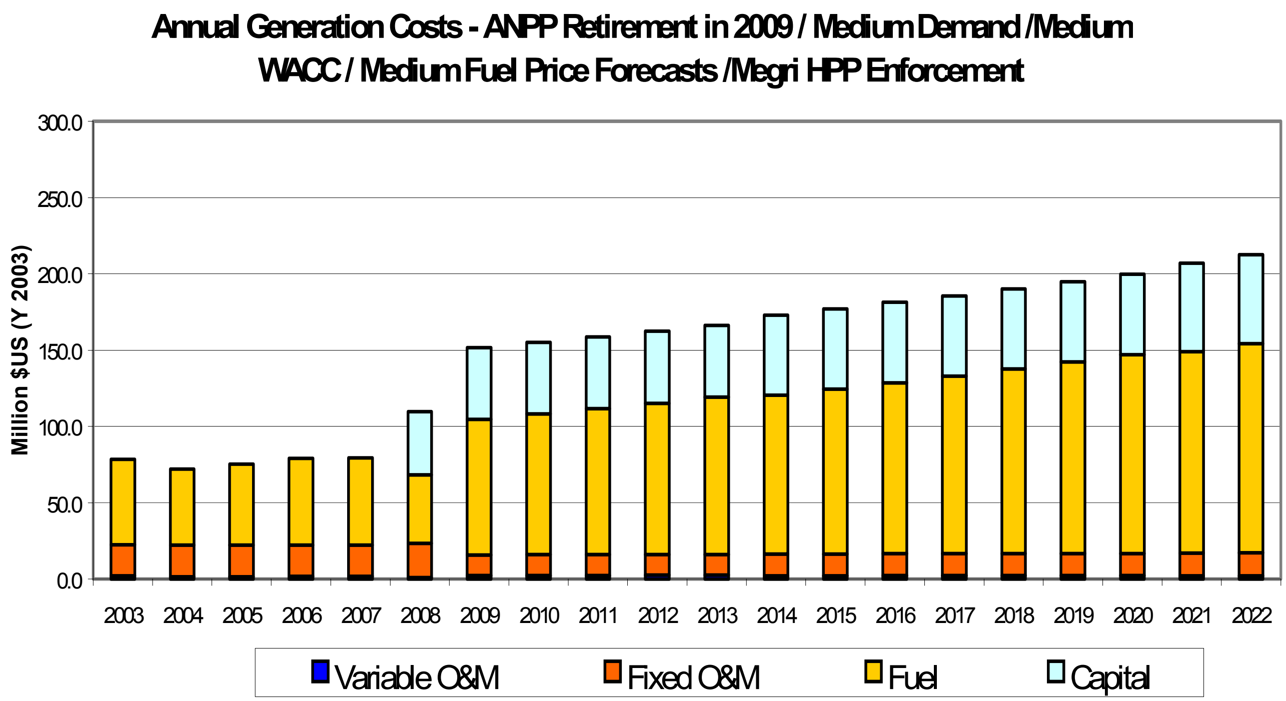


Figure 6.9. Annual Generation Costs for the Meghri HPP Enforcement Case

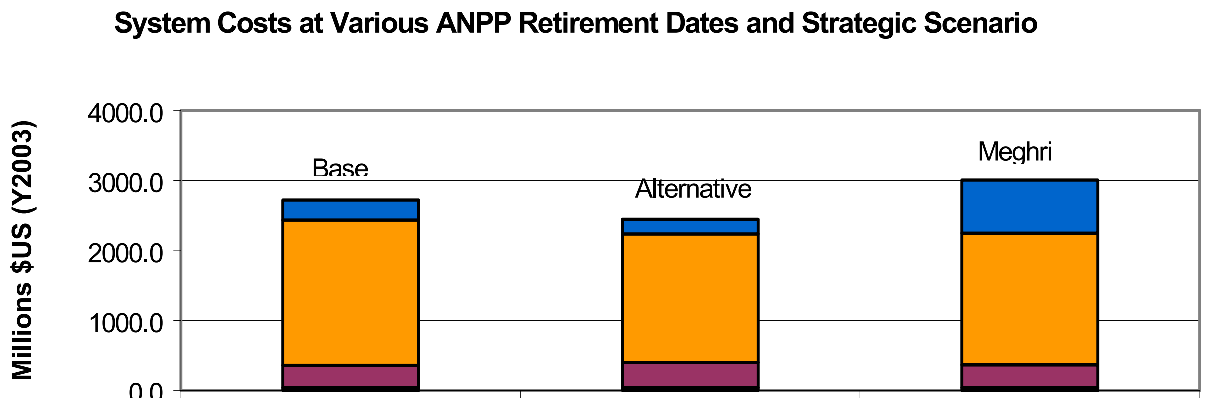


6.5 SUMMARY OF THE BASE, ALTERNATIVE AND MEGHRI HPP ENFORCEMENT CASES

The three main cases that were evaluated are the base case, the alternative base case, and the Meghri HPP Enforcement case. The lowest cost scenario is the alternative base case with the retirement of the ANPP at the end of 2014.

The Meghri Enforcement Case shows a significant incremental cost for its inclusion in the resource mix. The fact that Meghri HPP is only a 75 MW generating unit, completely replacing the ANPP with domestic resources will not only be difficult due to their differences in their load factors, but also the major impact on retail rates for the security of the system may not be justified. Even more important, the electric consumers may not be able to afford to pay for the additional energy security and be satisfied with the higher level of interruption with lower electric rates.

Figure 6.10. Net Present Value of Generation Costs for the Three Main Cases



	1	2	3
Capital	287.2	210.2	760.5
Fuel	2079.6	1836.6	1883.5
Fixed O&M	314.9	362.4	323
Variable O&M	42.1	37.5	40.8

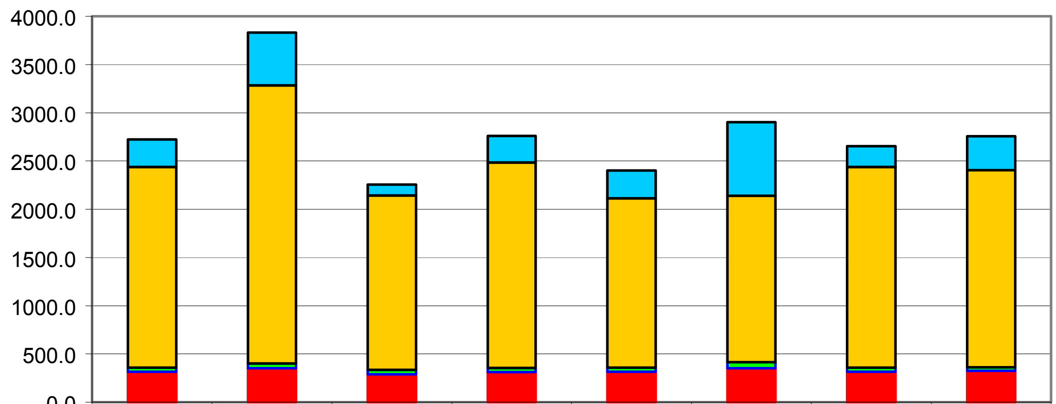
6.6 COMPARISON OF OTHER SCENARIOS TO THE BASE CASE

Several cases were analyzed to determine if how the decisions made in the preferred or selected resource plan will be impacted by the variables, which have a major impact on purchase power costs. The alternative base case was used in the comparison because it became the preferred long-term resource plan.

The results of the analysis are summarized below in Figure 6.11. The figure provides the total and a breakdown of generation costs in net present value terms ($2003). Details of all the scenarios can be found in Appendix C.

Figure 6.11. Production Costs for the Other Scenarios

Total Production Costs for Various Scenarios in millions USD (Y2003)
(2003 -2022)



	BASE	HIGH DEMAND	LOW DEMAND	HIGH FUEL PRICE	LOW FUEL PRICE	HIGH DISCOUNT RATE	LOW DISCOUNT RATE	30% RESERVE MARGIN -
Capital	287.2	545.9	115.5	275.8	287.2	763	217.4	352.6
Fuel	2079.6	2884.2	1806.4	2127.4	1757.4	1725.4	2079.6	2044.1
Variable O&M	42.1	48.7	45	42.8	42.1	61.8	42.1	36.6
Fixed O&M	314.9	352.3	289.9	313.2	314.8	352.9	314.8	324.3

6.6.2 Comparison of Base and Alternative Case to High and Low Demand Scenarios

For the high load growth scenario, there are additional investments that are required (more Gts) once the nuclear power plant is retired and more natural gas that is used for providing energy. This can be seen in Table 6.4 below that shows the increased average cost of sales for the high load growth case, especially related to natural gas share of the total costs. The cost impact of the retirement of the ANPP further justifies the continued operation of the ANPP until the end of 2014. There is plenty of existing generating capacity on the system until the retirement of the ANPP, so no different decision on the retirement of the old CHPs would be made from the decisions from the base case.

Looking at the low growth scenario, the decisions to retire the old CHPs are further re-enforced if the loads are lower. Though the impact of the retirement of the ANPP is less, the rate impact to electric consumers is still very large at the retirement date of the ANPP.

Table 6.4. Comparison of the Various Cases' Levelized Generation Costs – Part 1

($/MWH)

	BASE	ALTERNATIVE	HIGH DEMAND	LOW DEMAND
Variable O&M	0.46	0.41	0.53	0.49
Fixed O&M	3.42	3.94	3.83	3.15
Fuel	22.59	19.95	31.34	19.63
Capital Expenditure	3.12	2.28	5.93	1.25
Total Expenses	29.59	26.58	41.62	24.52

6.6.3 Comparison of Base and Alternative Case to Case with Changes in Variables

Five other future scenarios were analyzed, a high fuel price scenario, a low fuel price scenario, a high discount rate scenario, a low discount rate scenario, and a 30% reserve margin scenario (as compared to the 25% in the base case).

None of the analyses performed on these scenarios provided any additional recommendations that was developed from examining the base and alternative cases. Due to the fact that the significant natural gas use occurs only after the retirement of the ANPP and that the high and expected fuel price forecasts become closer throughout the study period, there difference in present value impacts are minor. The low fuel scenario showed a dampening of the average purchase power costs, but the change in costs at the time of retirement of the ANPP is still large. The levelized costs (see Table 6.5 below) high and low discount rate scenarios (high and low WACC) did not vary much from the rate base and provided no recommendations as to the preferred resource plan.

The reserve margin was examined to see if a higher reserve margin will have a significant impact on the recommendations for the preferred resource plan. As can be seen in Table 6.5 for the capacity reserve margin case, there is little difference in the levelized generation costs as compared to the base case. The reason for the small change is the change in the year one of the GTs is brought on-line. Such a decision would need to be made four or five years from the time the plant is needed. No such decision needs to be made for many years, especially if the ANPP continues to operate until the end of 2014.

Table 6.5. Comparison of the Various Cases' Levelized Generation Costs – Part 2

($/MWH)

	BASE	ALTERNATIVE	HIGH FUEL PRICE	LOW FUEL PRICE	HIGH DISCOUNT RATE	LOW DISCOUNT RATE	30% RESERVE MARGIN - RELIABILITY
Variable O&M	0.46	0.41	0.465	0.46	0.67	0.457	0.40
Fixed O&M	3.42	3.94	3.403	3.42	3.83	3.420	3.52
Fuel	22.59	19.95	23.114	19.09	18.75	22.595	22.21
Capital Expenditure	3.12	2.28	2.997	3.12	8.29	2.362	3.83
Total Expenses	29.59	26.58	29.978	26.09	31.54	28.834	29.96

7. CONCLUSIONS AND RECOMMENDATIONS

7.1 PREFERRED RESOURCE PLAN

Armenia's power sector has plenty of generating capacity. There is no need in the next two years to commit to any construction program for a new large generating plant. The continued expansion of the small hydro projects provide low-cost energy.

No economic replacement has been found for the ANPP. The GoA and the international donor agencies should commit to operate the ANPP to the end of its useful life (through 2014) and provide the appropriate funding required to maintain the unit in safe operating mode.

Continued development of small hydropower plants is warranted due to their low cost and that these domestic energy resource reduce Armenia's dependence on foreign fuel sources. The availability of low-cost financing provided through an international donor agency-supported revolving fund should be encouraged and put in place to continue the development of small hydro power plants and eventually other renewable resources.

7.2 TWO YEAR ACTION PLAN

The most important part of any least cost plan is the implementation phase. Typically a two-year plan is developed to start the implementation of the long-term recommendations of the least cost plan. The two-year action plan specifies the actions that the power sector should take to be consistent with the objectives of the long-term least cost plan.

The two-year action plan for the Armenian power sector, based on the results of the 2002 LCP process is:

- Fully analyze the physical conditional of each generating plant expected to continue its operation after 2004 and develop a comprehensive O&M and capital improvement plan;
- Retire the old thermal-powered plants as specified in the selected LCP;
- Fully fund and complete all O&M and capital improvements for all plants targeted for continued operations;
- Research and analyze the electric end-uses in order to determine what the future load pattern and sales will be for each end-use;
- Develop strategic energy plan that provides a rational development of natural gas as a replacement for electric end-use, especially related to residential heating and hot water uses;

7.3 INVESTMENT REQUIREMENTS FOR PREFERRED RESOURCE PLAN

The following Table 7.1 provides year by year capital investments required by the energy sector for the preferred resource plan.

Table 7.1. Annual Investment Plan for the Preferred Resource Plan

Years	Thermal	Hydro	Nuclear	Gas Turbines	Total
	(thousands of $ US)				
2002	12500	6470	0	0	**18970**
2003	9880	9416	3000	0	**22296**
2004	4720	10325	5150	0	**20195**
2005	0	12428	5305	0	**17733**
2006	2780	13305	5464	0	**21549**
2007	4720	5651	5628	4317	**20315**
2008	400	2140	5796	19426	**27762**
2009	0	2394	3582	19426	**25402**
2010	2200	796	3690	0	**6685**
2011	0	1073	3800	0	**4874**
2012	0	869	3914	5004	**9788**
2013	500	510	4032	27674	**32716**
2014	0	1949	0	51025	**52974**
2015	0	1903	0	47087	**48990**
2016	0	1681	0	23891	**25572**
2017	500	2236	0	0	**2736**
2018	0	2544	0	0	**2544**
2019	0	2220	0	0	**2220**
2020	0	1810	0	0	**1810**
2021	0	2113	0	0	**2113**
2022	0	3182	0	0	**3182**
Total	**38200**	**85016**	**49360**	**197850**	**370426**

The investment levels stated above do not include any costs of decommissioning the ANPP. The collection of those costs should be included in retail rates during the life-time of the power plant. If the power plant was to operate until 2014 and operate at its expected capacity factor, the collection from retail consumers would be approximately 1 dram/kwh starting January 1, 2003.

The Armenian population is limited in its ability to pay for services. The investments required in public utility sectors (electricity, gas, central heating, water, and telephone exceed $700 millions over the next 8 to ten years. It is hard to imagine that the consumers of these services will be able to afford to pay for these investments.

In light of this situation, the regulator will need to prioritize investments and try to minimize the negative impact of the reduced investments. Any additional funding beyond the least cost plan, say for strategic reasons, will need to be closely examined with all other priorities in the public service sectors.

7.4 STRATEGIC ALTERNATIVES AND COSTS

One strategic option was considered to determine the additional costs for securing energy security. The Meghri HPP was used as the proxy to determine the costs of reducing the dependence on natural gas by developing domestic resources. The additional cost, $284 mln ($2003), must be valued against the risk of losing gas supply in the near future and higher than expected prices of natural gas. An alternative to this option, would be securing of a second source of natural gas, which should be evaluated in the next round LCP process.