REPUBLIC OF ARMENIA ENERGY SECTOR NOTE

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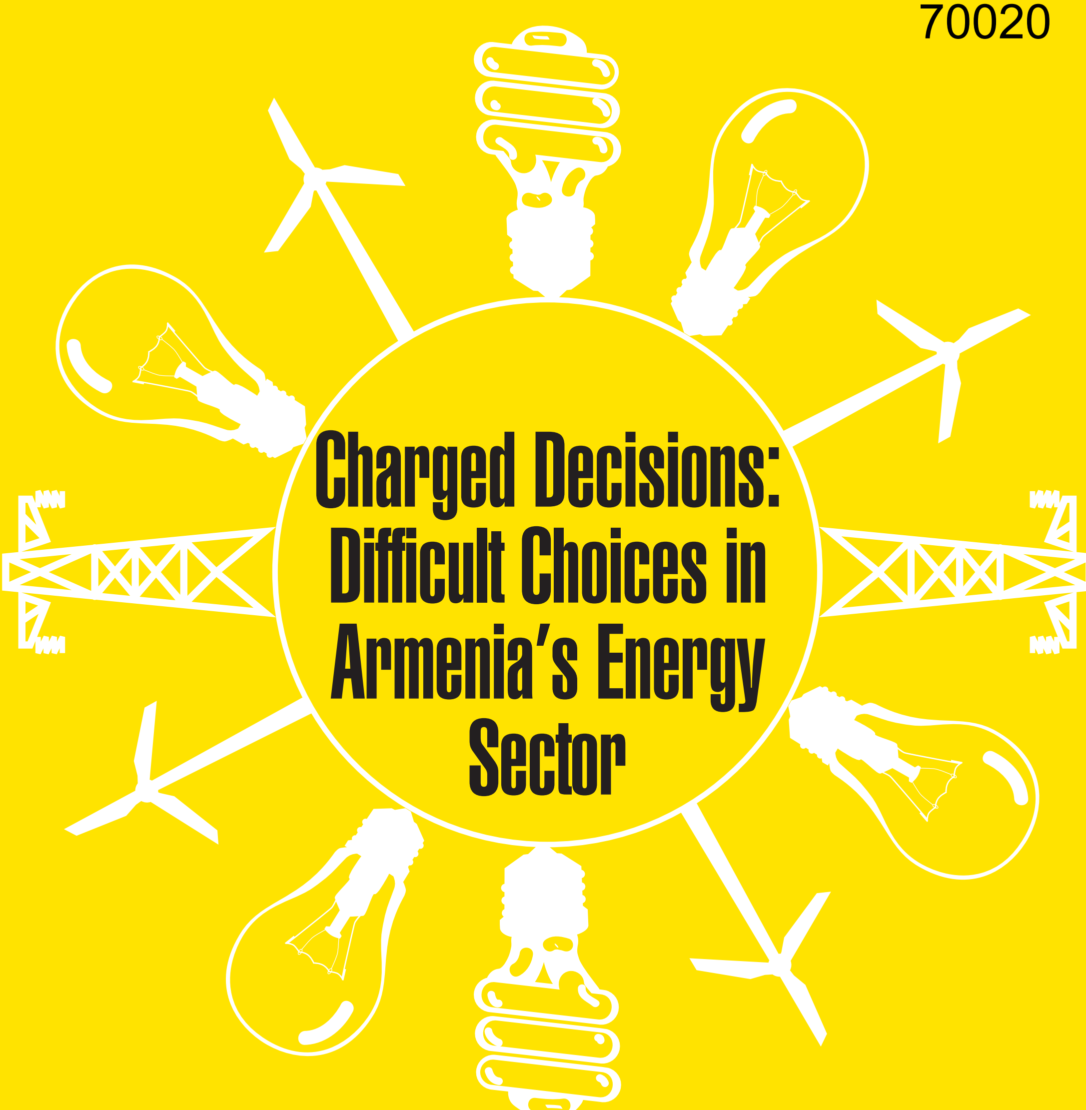

Charged Decisions: Difficult Choices in Armenia's Energy Sector

Sustainable Development Department
Europe and Central Asia Region

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World Bank

REPUBLIC OF ARMENIA

ENERGY SECTOR NOTE

Charged Decisions: Difficult Choices in Armenia's Energy Sector

Ani Balabanyan

Artur Kochnakyan

Gevorg Sargsyan

Denzel Hankinson

Lauren Pierce

Sustainable Development Department

Europe and Central Asia Region

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Acronyms and Abbreviations

AECL	Atomic Energy of Canada Limited
AERC	Armenian Energy Regulatory Commission
AMD	Armenian dram
BTU	British Thermal Unit
BWR	Boiling water reactor
CCGT	Combined cycle gas turbine
CEPA	Cambridge Economic Research Associates
CHP	Combined heat and power
CJSC	Closed joint-stock company
DCF	Discounted cash flow
DTI	UK Department of Trade and Industry
EBRD	European Bank for Reconstruction and Development
EDC	Electricity Distribution Company
EE	Energy efficiency
ENA	Electricity Networks of Armenia
EPC	Engineering and procurement contract
EPR	European pressurized reactor
GCR	Gas-cooled reactor
GDP	Gross Domestic Product
GE	General Electric
GoA	Government of Armenia
GWh	Gigawatt hours
HHI	Herfindahl-Hirschman Index
HPP	Hydropower plant
HVEN	High Voltage Electric Networks
IFC	International Finance Corporation
IMF	International Monetary Fund
kWh	Kilowatt hour
kV	Kilovolt
LCGP	Least cost generation plan
LEC	Levelized energy cost
m3	Cubic meter
MIT	Massachusetts Institute of Technology
MW	Megawatt
NPP	Nuclear Power Plant
NPV	Net present value

NRC	US Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
O&M	Operation and maintenance
OECD	Organization for Economic Cooperation and Development
PFBP	Poverty family benefit program
PHWR	Pressurized heavy water reactor
PSRC	Public Services Regulatory Commission
PWR	Pressurized Water Reactor
RAO UES	Russia's Unified Energy Systems (Russian electricity company)
RE	Renewable Energy
RM	Reserve margin
RMSE	Root Mean Square Error
SWU	Separated Work Unit
T&D	Transmission and distribution
Tcm	Thousand cubic meters
TPP	Thermal Power Plant
WWER	Water-water energy reactor

Executive Summary

Armenia's energy sector reforms have transformed the sector

Armenia's energy sector—specifically the electricity, natural gas and heating subsectors—have moved from severe crisis in the 1990s, to a stability more characteristic of developed countries than emerging markets. A mix of policy, legal, regulatory, and institutional reforms has achieved remarkable results.

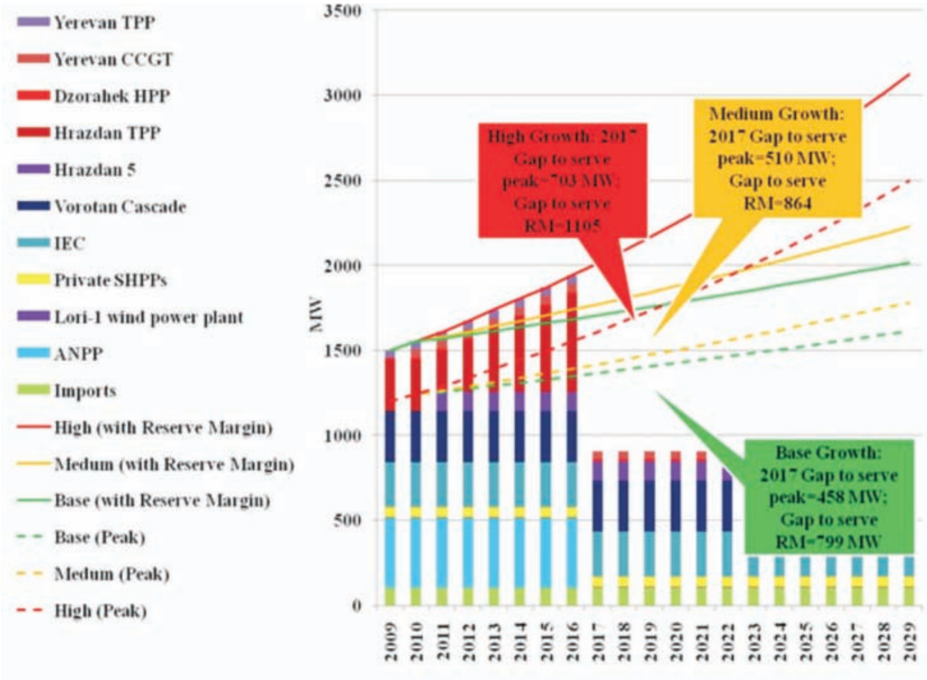
New challenges are similar to those faced by many developed economies

Thanks to reforms, policymakers can turn their focus to objectives common to many developed economies - optimizing the energy supply mix to provide affordable, reliable and sustainable energy services - rather than the common developing country focus on avoiding total system collapse. However, some serious challenges remain, and new challenges are emerging because much of Armenia's Soviet-era infrastructure is reaching the end of its useful life.

Armenia's principal challenges for the next 20 years are to: (i) ensure adequate energy supply; (ii) safeguard energy security, and (iii) keep energy supply affordable for customers while maintaining financial sustainability of the sector.

Challenge #1: Supply adequacy

Armenia will need at least 800 MW of new generating capacity when the existing nuclear power plant is decommissioned and the old, under-maintained gas-fired thermal power plants are retired. More than 1,000 MW of capacity (roughly half of the total installed capacity in the system) is expected to be retired by 2016 or shortly thereafter, and annual demand growth is estimated to be at least 1.4 percent. Roughly 1,400 MW of new capacity is in various stages of planning and may be developed. A new 1,100 MW nuclear plant represents the largest share of the planned new capacity, but financing for the plant has yet to be mobilized and Government may push back the original 2017 commissioning date. The challenge for Government will be to maintain the development schedule for the new nuclear power plant, or replace it with a viable alternative, or identify a stop-gap measure until the new power plant is completed. The figure below illustrates a forecast of installed capacity and winter peak demand until 2029, under three alternative demand scenarios, assuming nuclear and older thermal plants are retired as scheduled.



<u>Challenge #2:</u> Tenuous energy security.

Heavy reliance on imported fuels and the condition of old and under-maintained transmission and distribution assets puts Armenia at risk of supply interruptions, price fluctuations, and possible outages. Fuel for more than 90 percent of the country's energy needs is imported. Armenia is dependent on the import of hydrocarbons for all of its transport fuel, all gas used for industrial and residential heating, cooking, and all gas used to generate one-third of the country's electricity. On average, Armenia's transmission assets are 45 years old, and nearly 90 percent of 220 kV overhead lines require rehabilitation. The average age of distribution assets is 32 years. Roughly 42 percent of low-voltage substations are in deficient technical condition and some 14,000 autotransformers are under- or over-loaded.

<u>Challenge #3:</u> Increasing vulnerability to energy poverty.

Rising fuel prices and the need for new and more expensive generating units may make electricity less affordable for low-income customers. In 2009, poor spent about 10 percent of total household budget on electricity and gas. Energy poverty will be exacerbated if gas import prices continue to rise and the required substantial investments are made.

The magnitude of tariff increases will depend on load growth, the type of fuel used for the plant, fuel import prices, and the cost of financing. Tariffs will need to increase substantially, whether Armenia builds a nuclear plant, or meets demand through some alternative.

Either nuclear or gas-based generation are possible solutions, but there are…

From the perspective of supply adequacy, a large gas plant, or a series of smaller gas plants built over time are the only viable alternatives to the proposed nuclear plant. Tradeoffs exist between nuclear and gas in terms of their suitability for meeting the challenges identified above.

Technical tradeoffs*

Either nuclear or a gas plant can provide adequate supply, but gas plants can be built more quickly and units come in a range of sizes that can be scaled to meet demand. In contrast, nuclear plants can take at least 5-6 years to build and unit sizes are typically larger. Armenia's new nuclear power unit would be the largest in the country. Substantial reserve margin would be required to ensure that, if nuclear plant's turbine goes offline, Armenia's electricity system could still meet peak load.

Nuclear and gas plants differ in the type of load they are meant to serve. Typically in Armenia, gas plants have been used to serve seasonal peak load, but can also be run as baseload plants. Nuclear plants, in contrast, are baseload plants; they can be difficult to ramp up and down quickly and it is dangerous to run them at low capacity factors.

Supply security tradeoffs

Both the nuclear and the gas options in Armenia are dependent on imported fuels, and both uranium and natural gas can have fairly volatile and unpredictable prices. A new nuclear plant would provide better diversity of generation capacity than a comparably-sized gas plant, but a mid-sized (800 MW) gas plant, coupled with renewable energy (RE) and energy efficiency (EE) investments, provides nearly the same level of supply diversity as a nuclear plant.

Nuclear and gas plants have very different cost characteristics. Nuclear plants have high capital costs relative to gas plants, but low operating costs. Therefore, the most cost effective choice of a plant substantially depends on assumptions about fuel costs, availability of financing, and plant load factors. Assumptions about load factors depend, in turn, on expectations about growth in electricity demand. This paper analyzes the tariff impact of twelve cases, which differ in terms of:

- The cost of financing, estimated at 11 percent for commercial and 5 percent for concessional financing.
- The cost of gas, assumed at US$250 or US$500/thousand cubic meters (tcm).
- Electricity demand growth, estimated at 1.37 - 3.74 percent, depending on cost of generation and GDP growth.

The table below shows the lowest cost option or options for each scenario.

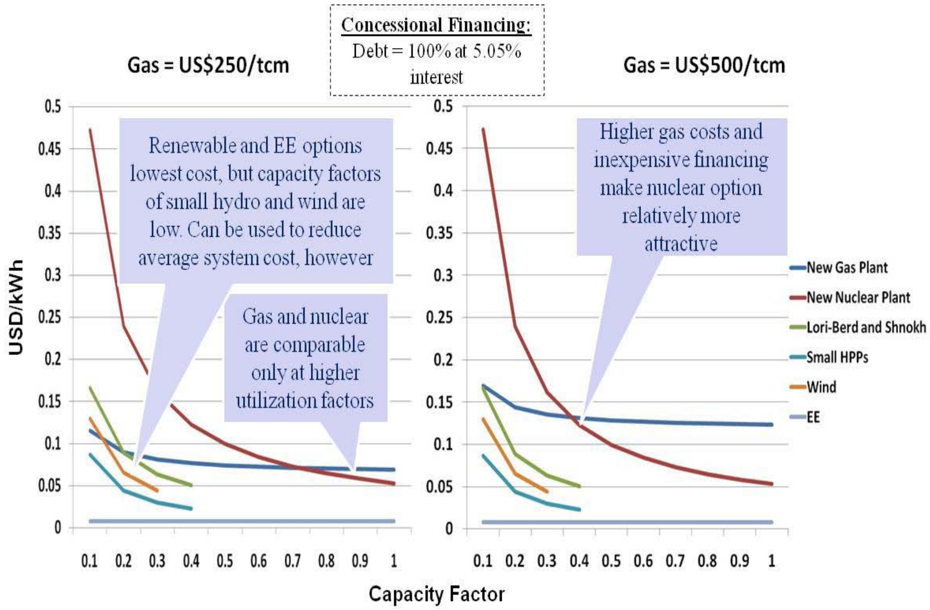
Cost trade-offs

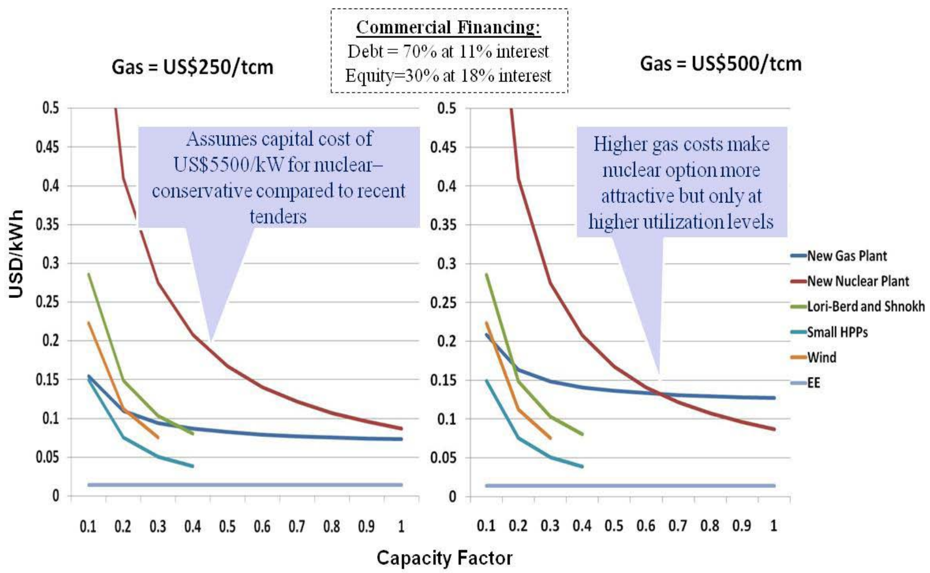
Assumptions	Base	Medium	High
Commercial finance; gas =US$250/tcm	Gas or gas with RE and EE investments (nearly identical)	Gas or gas with RE and EE investments (nearly identical)	Gas or gas with RE and EE investments (nearly identical)
Commercial finance; gas =US $500/tcm	Gas with RE and EE investments	Gas with RE and EE investments	Gas with RE and EE investments or Nuclear (nearly identical)
Concessional finance; gas =US$250/tcm	Gas with RE and EE investments	Gas with RE and EE investments	Gas with RE and EE investments
Concessional finance; gas =US$500/tcm	Nuclear	Nuclear	Nuclear

A nuclear plant is the lowest cost option (and hence has the lowest tariff impact), when concessional financing is available and gas prices are high. The gas options (a gas plant by itself, or a gas plant with RE and EE investments) are lower cost when commercial financing is used and gas prices are low.

When demand and gas prices are high, the nuclear and gas options coupled with RE and EE have roughly the same costs. Because of high capacity costs (and the need for substantial financing), nuclear plants incur cost whether they operate or not. Gas plants, in contrast, incur most of their costs only when they run. Therefore, the gas plants are relatively lower cost if overall demand or the shape of the load curve does not require continuous, high-level utilization of the plant. Nuclear plants are relatively lower cost when the plant is run nearly continuously close to full capacity.

The figure below shows the levelized energy cost (LEC) curves estimated for gas, nuclear, wind, hydro, and energy efficiency.**


Concessional Financing:
Debt = 100% at 5.05% interest
Gas = US$250/tcm
Gas = US$500/tcm
Renewable and EE options lowest cost, but capacity factors of small hydro and wind are low. Can be used to reduce average system cost, however
Gas and nuclear are comparable only at higher utilization factors
Higher gas costs and inexpensive financing make nuclear option relatively more attractive
USD/kWh
Capacity Factor
New Gas Plant
New Nuclear Plant
Lori-Berd and Shnokh
Small HPPs
Wind
EE


Commercial Financing:
Debt = 70% at 11% interest
Equity=30% at 18% interest
Gas = US$250/tcm
Gas = US$500/tcm
Assumes capital cost of US$5500/kW for nuclear–conservative compared to recent tenders
Higher gas costs make nuclear option more attractive but only at higher utilization levels
USD/kWh
Capacity Factor
New Gas Plant
New Nuclear Plant
Lori-Berd and Shnokh
Small HPPs
Wind
EE

… fiscal implications

In addition to tariff implications described above, there are also serious public finance implications that must be considered. The nuclear plant is estimated to cost around US$6 billion. This represents 64 percent of Armenia's 2010 gross domestic product (GDP), and more than three times the cost of the next most expensive supply option considered in this report (a large gas plant with RE and EE investments). The Government borrowing of that sum would increase Armenia's public debt to over 100 percent of estimated 2011 GDP, twice its statutory public debt limit of 50 percent of GDP.*** On the other hand, the Government borrowing for a new gas plant would add roughly US$700 million to public debt, keeping the public debt to GDP ratio at around 47 percent.

The Government needs to take a decision NOW

The Government is best placed to decide which set of assumptions are the most realistic. The best choice of generation option for Armenia depends critically on future gas import prices, electricity demand, and availability of financing for new plants. Given the long lead time required to build a new power plant, the decisions need to be made now.

The Government can take steps to improve on both options, including…

Whichever type of plant is built, the tariff impact will be substantial, and because of Armenia's dependence on imported fuels, diversity of supply will never be as good as it is now. There are, however, some actions the Government can take to improve both supply security and affordability, whether a new nuclear or gas plant is built. The Government needs to act quickly to improve system load factors, facilitate the use of renewable resources in electricity generation, and protect the poor from higher energy prices

improving load and capacity factors…

Armenia can reduce average supply cost of electricity by:

- Fostering higher regional exports during off-peak periods to raise baseload relative to peak.
- Implementing energy efficiency measures, which shave or shift peaks to baseload consumption.
- Using pumped storage on existing hydro cascades. Pumped storage can increase the capacity factor of the nuclear plant, using spare nuclear capacity to pump water back into higher reservoirs during off-peak hours. The pumped water can be stored and used to generate electricity when it is needed to serve system peaks.

fostering investment in renewable energy

Armenia can also reduce overall system costs by investing in or fostering private sector investments in renewable energy. As shown above, Armenia's potential renewable energy projects have lower LECs than new nuclear or gas plants. Therefore, running renewables can contribute to reduction of supply costs.

This is true for gas since renewables can be run instead of some gas generation thereby avoiding the fuel costs of gas generation. It is also true for nuclear if demand is high enough to maintain a high load factor at the nuclear plant. However, if demand is insufficient, renewables are unlikely to be dispatched or if they were, a portion of nuclear plant capacity would be left idle, while still incurring substantial costs.

As noted above, investments in RE and EE also improve energy security. Adding RE or EE to either a large gas or large nuclear plant, improves diversity in the supply mix and reduces dependence on imported fuels.

investing in T&D and storage

Armenia can improve energy security by rehabilitating and strengthening electricity transmission/ distribution infrastructure, and investing in petroleum and gas storage capacity.

and protecting the poor.

Substantial increases in end-user tariffs might make electricity and gas consumption unaffordable for a growing proportion of Armenian households, but tariffs must keep pace with future cost increases to maintain sector financial sustainability.

Government can maintain affordable tariffs for low-income customers through earmarked energy subsidies to poor households under the Poverty Family Benefits Program (PFBP).

Alternatively, Government could extend the 2011 temporary gas lifeline tariffs into the future and extend lifeline subsidies to the electricity sector. Lifeline tariffs can be funded from Government budget, or (more commonly) through cross-subsidies.

* This note offers no opinions on safety implications of building or operating a nuclear plant in Armenia.

** Many renewable energy generating options in Armenia are cost-effective but cannot provide as much baseload capacity, or firm peaking capacity as Armenia needs.

*** Assuming 2011 real GDP growth of 4.6%.

1 Introduction

More than a decade of ambitious sector reform has led to a period of stability in the Armenian energy sector. The sector faces challenges more typical of a developed economy than an emerging one: policymakers' concerns have shifted from avoiding total system collapse to optimizing the energy supply mix to provide affordable, reliable, and sustainable energy services.

However, some old challenges remain and new ones have arisen. Armenia is still vulnerable to energy supply disruptions; tariffs lag the full cost of service provision; and a significant investment backlog impedes progress in energy infrastructure.

The purpose of this note is to present the analysis of the challenges facing Armenia's energy sector, specifically, its electricity, natural gas, and heating subsectors.[1] The intention of the note is not to prescribe solutions, but to present analysis of options and tradeoffs that the Government can use to inform its decision-making.

The note is structured as follows:

- **Section 2** provides a brief overview of the sector in Armenia, the reforms implemented, and the Government's strategic objectives
- **Section 3** identifies the principal sector challenges
- **Section 4** recommends options to address the challenges.

The appendices present supporting information for the analyses. Appendix A provides background on the history of energy sector reforms in Armenia. Appendix B provides an overview of energy sector regulation, and Appendix C compares Armenia's energy sector key indicators to those of other countries. Appendix D presents physical characteristics of the Armenian electricity sector. Appendix E and Appendix F describe methodologies used to forecast demand and supply, respectively. Appendix G describes recent international experience with construction of nuclear plants.

[1] The note deals primarily with electricity or primary fuels delivered for stationary use (in homes, businesses or public facilities). It deals with transport energy fuels only peripherally, as part of its discussion of natural gas and petroleum use and storage.

2 Overview of Armenia's Energy Sector Reforms

Armenia's energy sector has undergone a series of reforms over the last fifteen years, which included privatization of the electricity distribution and gas companies, and some generating companies, establishment of an independent regulator, and development of a formal strategic plan for the sector. This energy sector overview highlights important outcomes from reforms and describes key sector characteristics.

2.1 What has Armenia Achieved?

Due to energy sector reforms, customers witnessed remarkable improvements in power supply service quality, reliability, and for gas customers - availability of connections.

In 1992, customers had only 2-4 hours of electricity supply per day; most households depended on firewood or electricity for heating. Fiscal and quasi-fiscal subsidies for the energy sector were a major drain on the state—about 11 percent of gross domestic product (GDP). Since 1996, 24-hour electricity service has been restored and gradually customers have switched to cheaper, more efficient gas heating. Meanwhile, tariff increases and operating efficiency improvements have helped create commercially viable service providers, technical and non-technical losses have decreased, and collections have increased. Now the energy sector is one of the largest taxpayers in Armenia. Supply security has also improved with new regional gas and electricity interconnections, thermal plant construction and rehabilitation, and growth in renewable energy generating capacity (primarily small hydro). Table 2.1 summarizes some improvements over the past decade. Appendix C compares data on Armenia's energy sector with those of other countries.

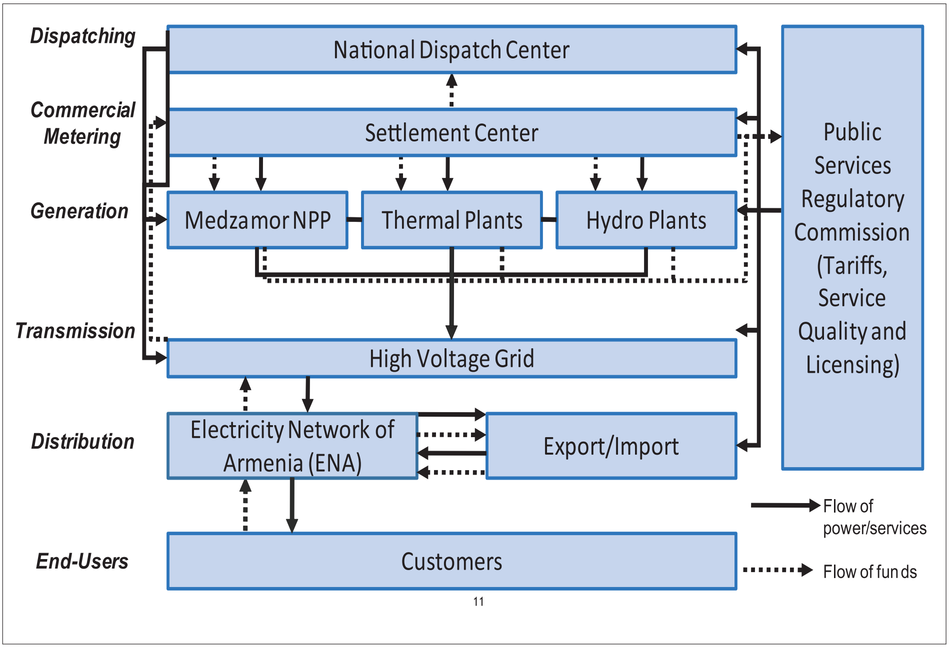
Table 2.1: Improvements in Armenia's Energy Sector over the Past Decade

	1999	2010
Electricity system losses (% of gross supply)	30%	13%
Collection rates for electricity distribution	88%	100%
Quasi-fiscal deficit	11% of budget	No quasi-fiscal deficit, and energy sector is now one of the largest taxpayers
Reduced reliance on gas for electricity generation	45% thermal	20% thermal
Safe gas-based heating	< 10%	> 69%
Gasification	< 80,000 residential subscribers	> 550,000 residential subscribers

Electricity

The formerly vertically-integrated electricity sector was unbundled; distribution and several generating plants were privatized. Around 48 percent of Armenia's generating capacity is now privately owned, including Hrazdan Thermal Power Plant (TPP), Sevan-Hrazdan Hydro Power Plant (HPP) and small HPPs. Figure 2.1 illustrates how power sector entities relate in terms of the flow of electricity and flow of funds.

Figure 2.1: Organizational Chart of Armenia's Electricity Sector



Armenia depends on three main types of power generation—thermal, hydro, and nuclear.[2] Nuclear power is used primarily to cover baseload consumption; thermal power covers seasonal peaks during the fall and winter low-water and cold season; hydro power covers daily load variation, but has reduced operable capacity during winter months. Figure 2.2 shows historical generation and consumption in Armenia. Figure 2.3 shows the 2010 annual pattern of generation.

2 The Lori-1 Wind Farm (2.6 MW) accounts for less than 0.1 percent of installed capacity in Armenia.

Figure 2.2: Historical Generation in Armenia (2003-2010)

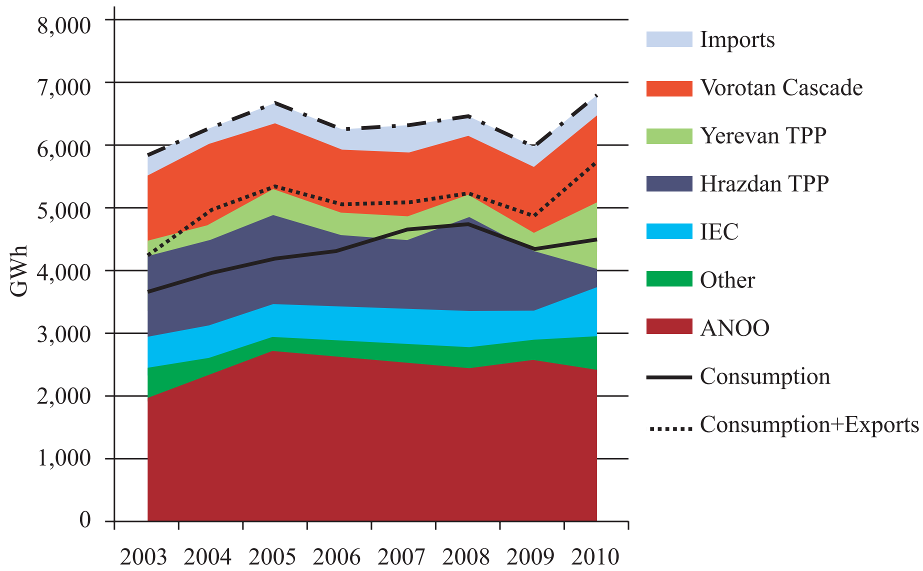
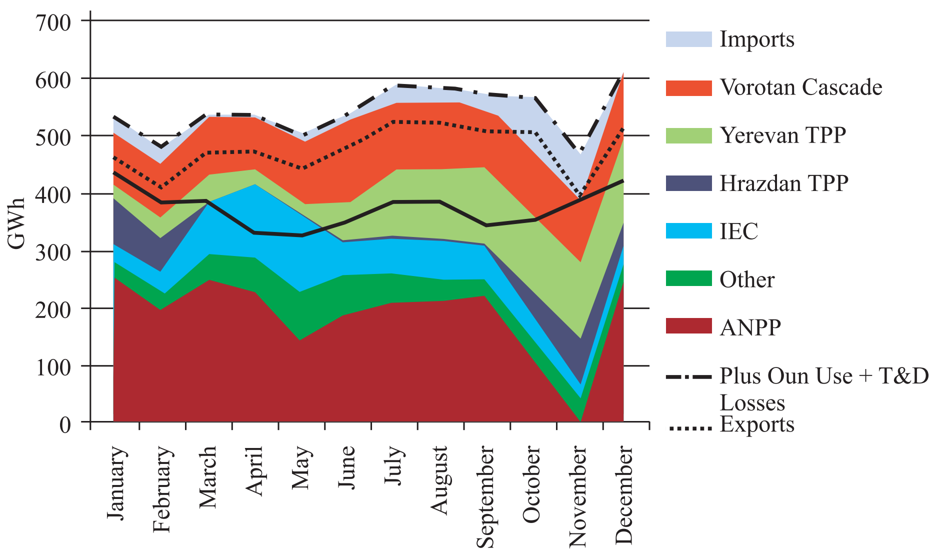


Figure 2.3: Monthly Generation Profile (2010)

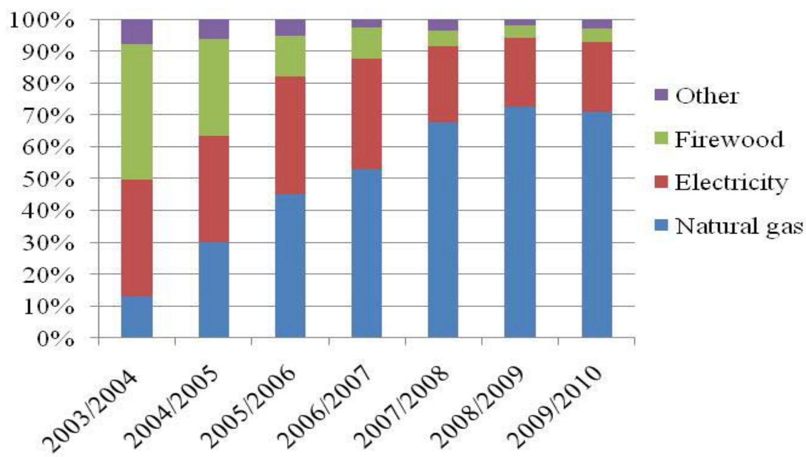


Heating and gas

District heating facilities, which once provided 55 percent of Armenia's residents with heat supply, have now nearly disappeared. In the early 1990s, the economic and energy blockade caused by the Nagorno Karabakh conflict led to bankruptcy of Armenia's heat supply companies and the shutdown of the majority of district heating systems. As a result, district heating declined dramatically – from 14.2 million m^2 of living space in 1990 to only 0.5 million m^2 in 2006.

The share of natural gas in the heating mix also increased over the past decade. From 2003 to 2009, the use of firewood for heating dropped nearly 91 percent, while the use of natural gas for heating increased by more than five times (see Figure 2.2). This trend was reversed during the 2009/2010 winter as the number of households using electricity and firewood for heating grew for the first time since 2006. The increase in natural gas tariffs in recent years is one possible explanation for the reversal of this trend. In 2008, the Government removed the natural gas subsidy, which led to a 42 percent increase in the natural gas tariff for residential customers. The gas tariff rose 14 percent in 2009 and increased by over 30% in 2010, reaching AMD 132/ tcm.

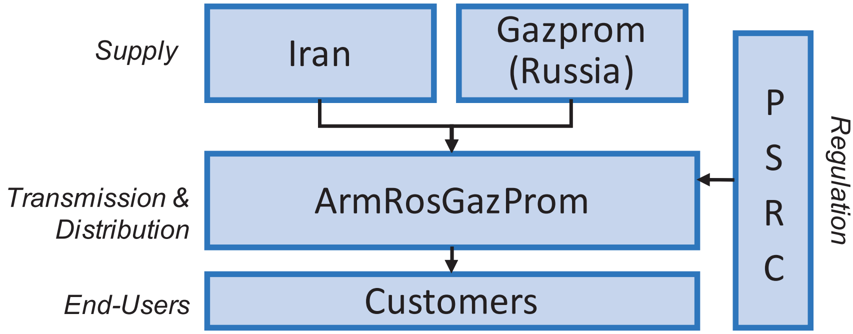
Figure 2.4: Heating fuel mix in Armenia, 2003-2010



Armenia also relies extensively on natural gas to generate electricity and produce industrial output. Armenia lacks domestic reserves and imports all natural gas from Russia and Iran. Natural gas from Russia comes via the North Caucasus-Transcaucasus pipeline and the Mozdok-Tblisi pipeline. Armenia recently began importing natural gas from Iran via a new Armenia-Iran pipeline. Under the agreement with Iran, Armenia agrees to exchange 3 kWh of electricity for 1 m^3 of Iranian gas. Construction of the pipeline on the Armenian side was completed in late 2008 and the pipeline began transporting gas in 2009. The agreement relies on the successful completion of a new 400 kV transmission line to Iran, soon expected to enter the construction phase.

The Russian company Gazprom owns 90 percent of the vertically integrated monopoly gas company, Armrusgazprom. Figure 2.5 illustrates relationships among various gas sector entities.

Figure 2.5: Organizational Chart of Armenia's Gas Sector



2.2 What are the Objectives for the Future?

The energy sector has the following strategic objectives: (i) maintaining energy security and independence; (ii) ensuring long-term affordable supply; (iii) and supporting national sustainable economic development through development of the energy sector.

Three policy documents - the Sustainable Development Program, Energy Sector Development Strategy, and National Program on Energy Savings and Renewable Energy - describe measures Armenia will use to achieve sector objectives. The principal among them are the following.

- Maintain sufficient capacity to meet short-, medium- and long-term demand
- Support energy savings, energy efficiency and renewable energy
- Increase use of domestic energy resources
- Diversify energy resources

2.3 Conclusion

Armenia's energy sector has moved from severe crisis to a stability that is more characteristic of developed countries. A combination of policy, legal, regulatory and institutional reforms resulted in remarkable achievements. Now, policymakers have shifted their focus from avoiding total system collapse to more mundane objectives of optimizing the energy supply mix to provide affordable, reliable and sustainable energy services.

Nevertheless, significant challenges remain for Armenia to implement these measures and meet overall strategic objectives; these challenges are described in Section 3.

3 Principal Challenges in the Energy Sector

Armenia faces three principal challenges in the energy sector:

- **Emerging supply gap.** Steady demand growth and old under-maintained energy infrastructure that must be shut down, including several generation facilities (roughly 1,300 MW of operable capacity), means that Armenia must build new plants to meet the supply gap that will be emerging in 2017.
- **Maintaining energy supply reliability.** Heavy reliance on imported fuels, old and under-maintained electricity transmission and distribution infrastructure, and old gas transmission infrastructure make Armenia prone to supply interruption, price fluctuation, and outage risks.
- **Maintaining affordable tariffs.** Rising fuel prices and the need for new, more expensive electricity generating units may jeopardize the affordability of gas and electricity for low-income customers.

Sections 3.1 to 3.3 discuss those challenges in further detail.

3.1 Emerging Supply Gap

Unless new plants are commissioned to replace those scheduled for retirement,[3] Armenia could fail to meet peak demand as early as 2017 due to aging infrastructure, steady demand growth, and a tariff structure that encourages inefficient consumption.

Dilapidated infrastructure

More than half of Armenia's generating capacity is at or near the end of its useful operating life; many units now operate well below installed capacity. Figure 3.1 shows installed capacities compared to the operating capacities of Armenia's generating units.

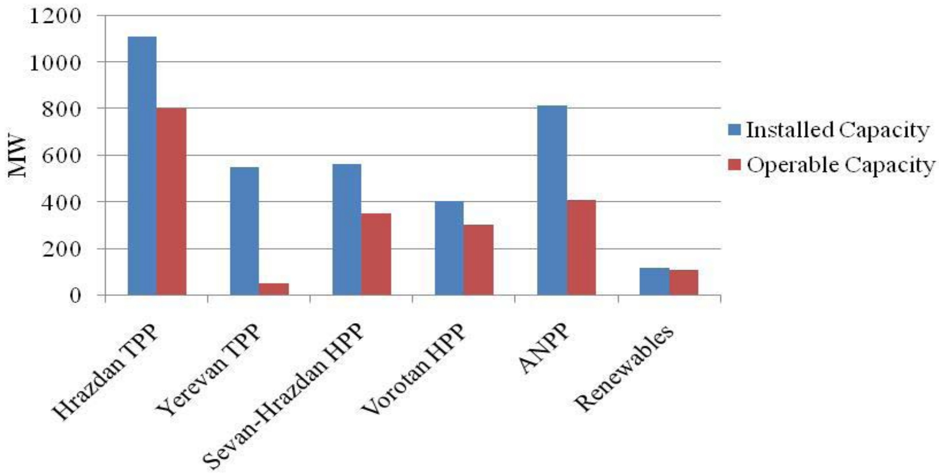
Eventually, the Government intends to decommission the 400 MW Metsamor Nuclear Power Plan (NPP) after sufficient replacement capacity is commissioned. Units 1-4 at Hrazdan TPP (800 MW operable capacity), and Units 1-2 at Yerevan TPP (50 MW operable capacity) must be discontinued due to age and inefficiency.[4] The nuclear plant serves baseload; Hrazdan TPP covers seasonal peaks; and Yerevan TPP primarily serves a large chemical plant. To simplify the analysis, this study assumes that the Metsamor NPP, and Hrazdan and Yerevan TPPs will be retired at end-2016.[5]

[3] For analytical simplicity, this study assumes that the Metsamor Nuclear Power Station, and Hrazdan and Yerevan TPPs will be retired at end-2016, and a new plant will be commissioned at the beginning of 2017.

[4] The Hrazdan TPP requires 371 grams of fuel per kWh (g/kWh) generated. The Yerevan TPP requires 374 g/kWh. In contrast, new gas-fired thermal power plants Hrazdan 5 and Yerevan CCGT require 260-270 g/kWh and 170 g/kWh, respectively.

[5] In practice, the Government may extend the life of some plants until replacement capacity can

Figure 3.1: Installed Versus Operating Capacity of Generation



Source: World Bank. *Armenia Power Sector General and Investment Overview.* November 2009.

In 2010, Armenia added 240 MW of new gas generating capacity with the commissioning of the combined-cycle gas turbine at Yerevan TPP. More new gas capacity, Hrazdan Unit 5, is expected to come online in 2011. However, roughly 75 percent of the new capacity at Yerevan TPP and Hrazdan 5 is expected to be used for the electricity-gas swap with Iran and therefore will not be available for domestic consumption.[6]

Demand growth

Electricity consumption in Armenia grew steadily in 2003 - 2009 (5.72 percent annually in summer, 3.48 percent annually in winter), but fell 7.4 percent between 2008 and 2009. Consumption revived again in 2010 with the revival of the economy, growing by around 3 percent as GDP grew roughly 2 percent.[7] Consumption is likely to grow again as Armenia's economy recovers from the global financial crisis. Official forecasts put real GDP growth at 4.6 percent for 2011.[8]

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be commissioned.

[6] In May 2004, Armenia signed an agreement with Iran to exchange 3 kWh of electricity from Armenia for 1 m^3 of Iranian gas. Gas from Iran is imported via a newly constructed Armenia-Iran gas pipeline. Construction of the pipeline on the Armenian side was completed in late 2008 and the pipeline began transporting gas May 2009. The pipeline has a capacity to transport 7 million m^3 of gas daily.

[7] GDP data from National Statistics Service of the Republic of Armenia (ARMSTAT). (http://www.armstat.am/en/?nid=126&id=01001&submit=Search). Accessed on April 13, 2011.

[8] Arka News Agency. "Project GDP Growth for 2011 Quite Feasible, MP Says". (http://www.arka.am/eng/economy/2011/04/01/24953.html). Accessed on April 13, 2011.

The need for new generating capacity depends critically on assumptions about demand growth over the next 5-6 years. The planned retirement of the Metsamor NPP, and the age and inefficiency of Hrazdan and Yerevan TPPs create the need for a substantial amount of new generating capacity in the next 5-6 years.[9]

Armenia needs at least 800 MW of new, operable generating capacity by 2017, under modest demand growth assumptions, in order to meet peak load and maintain 25 percent reserve margin. Higher GDP growth - comparable to Armenia's sustained double-digit GDP growth between 2003 and 2008 - would require at least 1,100 of new operable capacity in 2017 alone, and substantially more capacity in subsequent years.[10]

Figure 3.2 shows a forecast of installed capacity and winter peak demand until 2029, under three demand scenarios:

- A "base demand" scenario, which reflects the recent (2011) International Monetary Fund (IMF) GDP forecasts for Armenia
- A "medium demand" scenario, which forecasts GDP based on historical GDP growth in 2004–2009.
- A "high demand" scenario, which forecasts GDP growth based on historical GDP growth during 2003-2008. This time period excludes 2009 economic downturn, effectively treating the global recession as a macroeconomic anomaly rather than a normal part of the economic cycle.

Box 3.1 describes in more detail the assumptions used to forecast the electricity supply and demand gap in 2017.[11] Section 4 shows the estimates of demand depending on the type of new plant to be built and the cost of financing used.

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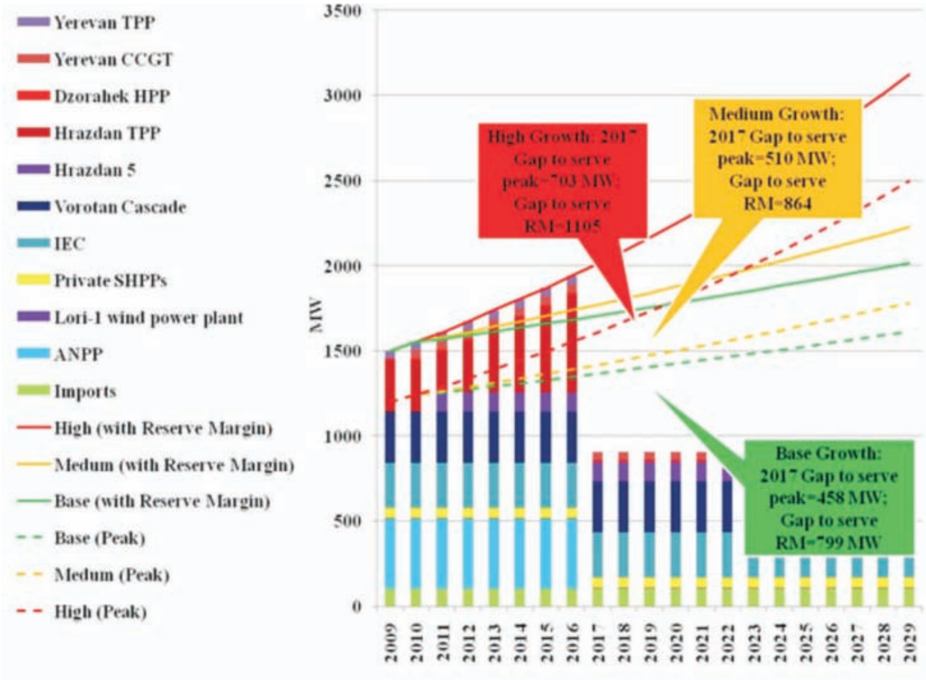
9 This note assumes that the Metsamor Nuclear Power Station will be decommissioned in 2016 but Government stated in 2010 that, because of delays in starting its work on a new nuclear plant, it may keep the plant running beyond 2016, until a new plant can be commissioned.

10 These forecasts assume the system maintains a 25 percent margin for reserve capacity.

11 Appendix E provides more detail on the methodology used to produce demand forecasts. Appendix F describes in more detail the assumptions made about electricity supply in Armenia, for the purpose of estimating the generation and capacity gaps.

Figure 3.2: Gap between Installed Capacity and Peak Winter Demand in 2017 under Three Demand Forecasts



Box 3.1: Key Assumptions Used to Estimate the Emerging Supply Gap

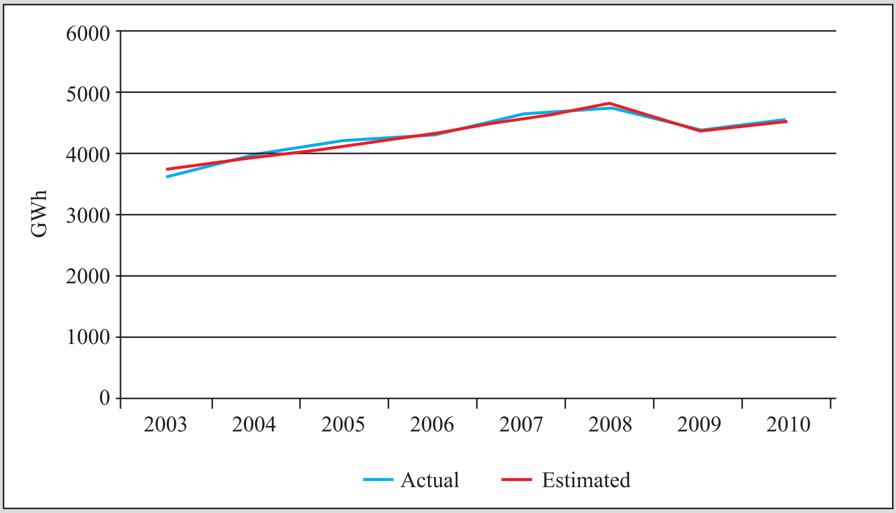
Assumptions about Supply

- Metsamor NPP and old TPPs retire in 2016.
- Yerevan CCGT comes online in 2010, and Hrazdan 5 comes online in 2011, but 75 percent of their energy and capacity is dedicated for export.
- Meghri HPP comes online in 2019, but all of its capacity is used for export.
- Reserve margin = 25 percent.

Assumptions and data used to forecast demand

- An econometric model predicts residential and non-residential electricity demand (in GWh) using historic, quarterly data on GDP, real tariffs and their relation to electricity demand*
- The shape of the load curve does not change (the relationship of peak to average load); therefore, peak load grows at the same rate as consumption.

The figures below compare model estimates with actual historical consumption data.



Demand Cases:

- **Base Growth Case: Annual electricity consumption growth of 1.37 percent.** Average GDP growth is 4.0 percent per year during 2011-2030.** Real electricity prices do not change.***
- **Medium Growth Case: Annual electricity consumption growth of 1.91 percent.** Average GDP growth is 5.6 percent per year during 2011-2030. Real electricity prices do not change.
- **High Growth Case: Annual electricity consumption growth of 3.74 percent.** GDP grows at roughly 11 percent per year during 2011-2030. Real electricity prices do not change.

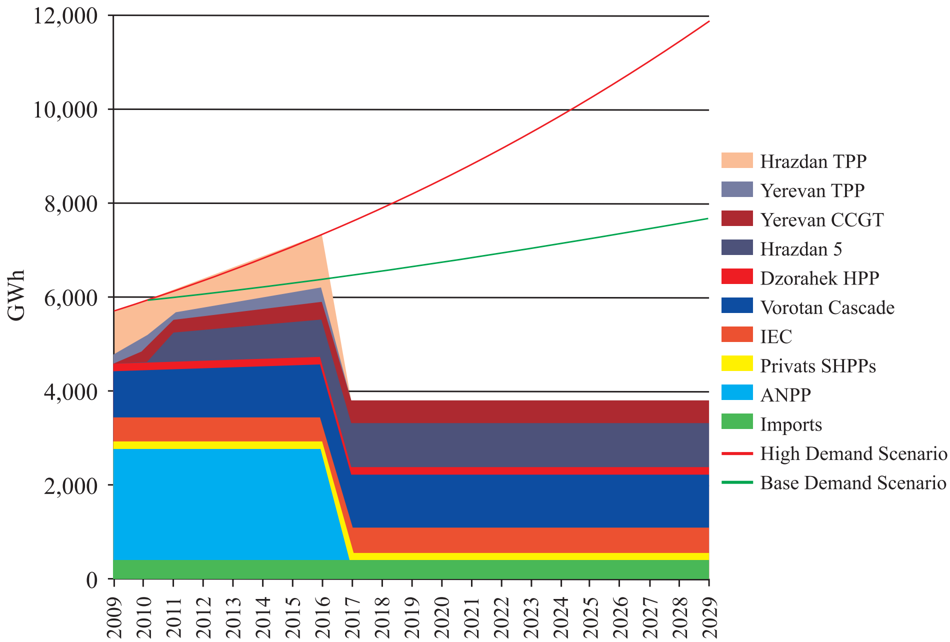
* As with all forecasts, uncertainty exists in electricity demand forecasts produced for this paper. Appendix E describes how assumptions about price inelastic residential demand for electricity, and historically low income elasticity of demand in Armenia may over- or under-state future demand, respectively.

** IMF World Economic Outlook 2011.

*** In practice, the cost of new plants is likely to require higher nominal and real tariffs, which will have a feedback effect on demand. Section 4 considers the effects on demand of the cost of supply options.

Figure 3.3 illustrates implications for consumption and generation; the retirement of old nuclear and thermal units will leave a substantial generation gap.

Figure 3.3: Gap between Electricity Generation and Consumption under Highest and Lowest Demand Forecasts[12]



Roughly 1,400 MW of new capacity is in various stages of planning, and may be developed. A new 1,100 MW nuclear plant represents the largest portion of the new capacity. There may be potential for new renewable energy capacity, comprising primarily mid-size hydro plants (Shnokh, Loriberd), and various private small hydro and wind plants. These new units represent 511 MW of installed capacity, of which 168 MW would be available to meet Armenia's winter peak. Roughly 25 percent of the Yerevan CCGT and Hrazdan 5 gas plants are also expected to be made available to serve domestic load.[13]

Inefficient tariff structures

- Armenia's tariff structure offers customers reasonably efficient signals for consumption, but there is room for improvement. The structure for end-user gas and electricity tariffs encourages inefficient consumption.

[12] Consumption in this figure includes consumption for export, energy used by generators themselves (own use), transmission and distribution losses.

[13] This analysis does not consider the hydropower plant planned at Meghri, because for the most of the time period covered by the analysis the plant is expected to be dedicated for export to Iran.

- *Tariffs fail to reflect the difference in winter/ summer generation costs.* About 22 percent of Armenian households use electricity to heat their homes even though natural gas-based heating is more efficient. Old gas-fired thermal plants with lower efficiency must be used to serve peak load created by electricity demand for heating.[14] Summer and winter tariffs are identical although average costs for winter generation are higher. Residential customers now pay a daytime tariff of AMD 30/kWh (US$ 0.081/kWh) and a nighttime tariff of AMD 20/kWh (US$ 0.054/kWh), year-round. Non-residential customers pay nighttime tariffs of AMD 17/kWh (US$ 0.046/kWh) and daytime tariffs that depend on the voltage level at which they are served and the connection type, ranging from AMD 21/kWh (US$ 0.057/kWh) for high voltage customers, to AMD 30/kWh for medium-voltage customers. Implementing seasonal tariffs to reflect the higher cost of winter electricity generation would provide an incentive for customers to switch to more efficient heating sources. Instead, now they are virtually subsidized and have no incentive to switch to efficient heating sources.
- *Single-part end-user electricity and gas tariffs give utilities no incentive to encourage energy savings by end-users*. Electricity and gas tariffs in Armenia are charged per unit of energy consumed. With these "one part" tariffs, energy service providers have an incentive to sell as much energy as they can in order to recover their fixed costs. In contrast, a two-part tariff, ensures that the utility recovers its fixed costs, regardless of customers' consumption levels.
- *The gas tariff structure induces inefficient consumption for some customers*. Natural gas customers are categorized depending on their monthly volume of consumption: those with consumption greater than 10,000 m^3/month pay a tariff of AMD 88/m^3 (US$ 0.24/m^3), and those with consumption less than 10,000 m^3/month pay a tariff of AMD 132/m^3 (US$ 0.35/m^3). There is evidence that this structure creates a perverse incentive for customers whose heat consumption is close to 10,000 m^3/month.[15] In order to obtain the lower price, these customers intentionally use excessive amounts of gas and are disinclined to invest in energy savings measures.

3.2 Maintaining Energy Supply Reliability

Supply reliability is a challenge for Armenia because of the condition of its assets, the emerging supply gap, and geopolitical factors. Supply reliability can be measured in terms of supply adequacy and supply security. Supply adequacy means having enough capacity to serve the customers when they need it. Supply security is the ability to withstand sudden disturbances such as accidents or fuel supply interruptions. The first threat to supply reliability (the the emerging supply gap) was described in Section 3.1. The con-

[14] Electric heating conversion efficiency in Armenia is roughly 25 to 30 percent. In contrast, individual gas heater efficiency is around 90 percent.

[15] These customers mainly include small heat-only boiler stations supplying one or more buildings or SMEs burning gas for production or heating needs.

dition of Armenia's transmission and distribution assets, and, geopolitical factors further threaten Armenia's energy supply reliability.

The average age of Armenia's transmission assets is 45 years. Nearly 90 percent of 220 kV overhead lines require rehabilitation.[16] The average age of distribution assets is 32 years. Roughly 42 percent of low voltage substations are in very poor technical condition and 14,000 autotransformers are under- or overloaded.

Geopolitical factors are a persistent threat to Armenia's energy supply reliability. Maintaining sufficient access to energy markets or, as an alternative, reserves and supply security pose significant challenges. Supply reliability could be threatened if supply of any of the imported fuels was interrupted. Fuel for more than 90 percent of Armenia's energy needs is imported. Armenia is dependent on the import of hydrocarbons for transport, all gas used for heating, cooking, and generation of electricity (roughly one-third of the country's generating capacity), and all of the uranium needed for the Metsamor nuclear power plant.

Losing a single pillar of national electricity generating capacity - nuclear (400 MW), hydro (1,000 MW), or gas-fired thermal (1,700 MW) - would create potential difficulty in meeting peak demand. The electricity system is unlikely to fail if a single thermal unit or hydro plant is lost, but since suppliers are limited for any single fuel source, all plants using that fuel would be affected. During the 1993-95 energy crisis, a supply interruption shut down all gas-fired generators in Armenia.[17] The new gas pipeline to Iran increases supply security, but does not eliminate potential for import disruptions.

3.3 Affordability of Tariffs

In 2009, poor Armenian households spent roughly 10 percent of their total household budgets on electricity and gas, which is defined as living on the edge of "fuel poverty" (European Bank for Reconstruction and Development (EBRD)). Low-income customers will likely continue to experience fuel poverty due to rising fuel prices and the high capital costs anticipated when new generating plants are built and transmission and distribution lines are rehabilitated, as described below.

Rising fuel prices

Imported natural gas prices are likely to increase in Armenia, which will mean higher generation costs and higher electricity tariffs. Armenia's gas import price (US$180/ tcm)

[16] All electrical equipment (for example, switch-gears and circuit breakers) and most power equipment at the high voltage sub-stations were replaced during 1998-04 with World Bank and KfW financing, but a major bottleneck remains at Hrazdan TPP due to the poor condition of the Hrazdan TPP 330 kV substation.

[17] Gas supply interruption posed an even greater problem during 1993-95 because Armenia lacked capacity from the Metsamor nuclear plant, which was shut down until 1995 due to the 1988 earthquake.

is well below that of Western European countries (US$ 500/tcm in 2008). The global recession reduced natural gas prices to about US$ 325/tcm in 2010, but prices are likely to return gradually to 2008 levels. During the first quarter of 2011, Gazprom's average wholesale price was US$ 346.[18] It is widely anticipated that Armenia will eventually face Western European prices, which will will substantial increase the costs of gas-fired generation and electricity tariffs.

Rising capital costs

The cost of new generating capacity and rehabilitation of transmission and distribution assets will also require substantial tariff increases. The average nominal cost of generation is likely to increase 2-4 fold if a new nuclear plant is built, depending on the financing arrangements used and the path of demand growth. This will have a direct impact on customers if end-user tariffs are to be maintained at cost recovery levels. Section 4.3 compares the cost implications of different financing options (commercial and concessional) under different demand scenarios (high, medium and base). Section 4.3 also compares the levelized cost of a new nuclear plant to the levelized cost of other types of generation.

3.4 Conclusions

Principal challenges for Armenia are closely tied to the strategic objectives of the sector. These include the following:

- **An emerging supply gap.** By 2017, Armenia will need at least 800 MW of new generating capacity as old under-maintained energy infrastructure is retired and demand grows steadily. By 2016, it is anticipated that nearly 1,300 MW of operable capacity will be retired; the annual demand growth is estimated to be at least 1.4 percent during 2011-2016. The Government's challenge will be to maintain the schedule to bring the new nuclear power plant on line, or identify a viable alternative as a replacement or a stop-gap measure until the new power plant is completed.
- **Tenuous energy supply reliability.** Security of fuel supply and the poor condition of electricity transmission and distribution assets are critical and persistent threats to energy sector sustainability in Armenia.
- **Rising energy poverty.** Rising fuel prices and the need for new, more expensive generating units may jeopardize affordability of electricity and gas supply for low-income customers. The lingering effects of the financial crisis and the need for continued tariff increases will increasingly push lower-income Armenians toward the brink of fuel poverty.

[18] "Ukraine Looks to Texas for an Energy Path." May 4, 2011. Andrew E. Kramer. The New York Times. http://www.nytimes.com/2011/05/05/business/global/05shale.html (accessed on May 5, 2011).

4 Potential Solutions to the Challenges

Armenia can meet energy sector challenges by coupling investment with careful policy action. The priorities include the following:

- **Add new capacity.** Armenia needs new capacity that uses domestic resources and maintains diversity in the generation mix, at least cost.
- **Improve energy security.** Armenia can improve supply reliability by investing in transmission and distribution network rehabilitation and petroleum and gas storage.
- **Protect low-income customers.** Targeted support will be needed for vulnerable customers to cushion the impact of tariff increases.

Section 4.1 evaluates options for new generating capacity. Section 4.2 describes options to improve energy security. Section 4.3 describes options to improve energy supply affordability. Section 4.4 summarizes findings.

4.1 New Capacity

By 2017, Armenia will need 800 – 1,100 MW of new generating capacity to meet peak demand and reserve margins, as discussed in Section 3. The Government aims to provide reliable, secure and affordable supply. This can be done by building new generating capacity that:

- **Is least-cost.** Armenia needs capacity with low life-cycle costs, which will have the lowest impact on tariffs. Higher cost options will aggravate affordability of the electricity tariffs, or - if higher costs are not passed through to customers in the form of higher tariffs - will require substantial government subsidies.
- **Provides adequate supply.** Armenia needs sufficient capacity to meet peak demand and provide a reasonable reserve margin. This analysis rates a new capacity option as adequate if it comes close to meeting peak demand plus the required reserve margin through 2021 (five years after the supply gap emerges).[19]
- **Maintains diversity of the generation mix.** Armenia needs new capacity that maintains diversity in the mix of fuels used for electricity generation.

The following subsections evaluate four new capacity options against the aforementioned criteria. The four options include the following:

1. **Nuclear-only:** The Government plans to build a new 1,000 – 1,100 MW nuclear plant at the site of the Metsamor plant. This note assumes 1,100 MW plant.

[19] The study assumes a supply option is adequate if it comes within 100 MW of meeting peak demand plus the required reserve margin.

2. **Gas-only:** The analysis also considers the extent to which a new gas plant would meet the evaluation criteria. Because gas plants are typically available in a wide range of sizes, the analysis below assumes that gas plants are "right sized" to meet each demand scenario for 2017: an 800 MW plant is built to meet demand in base and medium growth scenarios; an 1100 MW plant is built to meet the demand in high growth scenario.
3. **Nuclear + RE + EE:** This option combines an 1,100 MW nuclear plant with 550 MW of renewable energy generating capacity (168 MW operable capacity) and 110 MW of energy efficiency measures[20]
4. **Gas + RE + EE:** This option combines a "right sized" gas plant with 550 MW of renewable energy generating capacity (168 MW operable capacity) and 110 MW of energy efficiency measures.

Least-cost supply

Life-cycle costs depend on capital costs and operating costs. Capital costs depend critically on the cost of investments and the cost of financing used (the interest rate paid on loans or the equity return required by investors in the form of dividends). Operating costs depend critically on the cost of fuel. Plant utilization is also an important factor. A plant that operates more frequently and at higher levels of capacity than another identical plant, will have higher operating costs per kilowatt-hour, but lower capital costs, because the capital costs can be spread out over more kilowatt-hours.

Figure 4.1 and Figure 4.2 compare the LECs of different types of generating capacity under various assumptions for gas import prices and financing arrangements. The LECs show how costs (on the y-axis) change as utilization factors (on the x-axis) change.

[20] Estimates of the capacity provided by energy efficiency measures are based on World Bank Energy Efficiency Study estimates from 2008.

Figure 4.1: Comparison of Levelized Energy Cost of Generation Options (Concessional Financing)

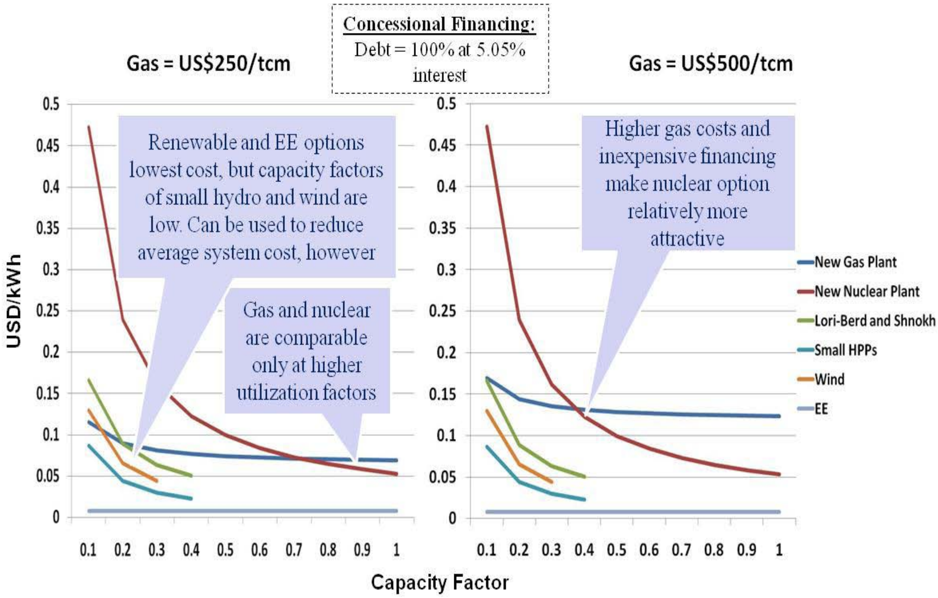
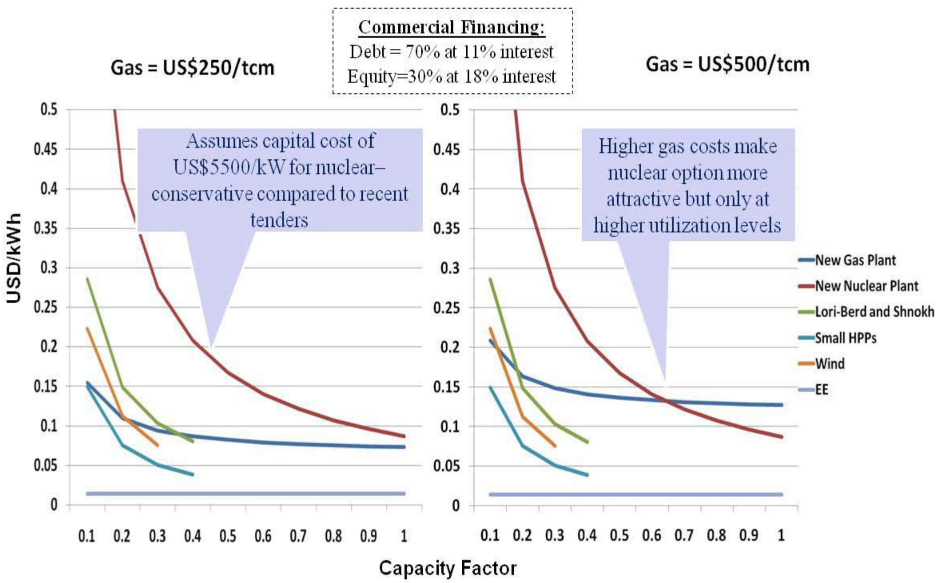


Figure 4.2: Comparison of Levelized Energy Cost of Generation Options (Commercial Financing)



The analysis in Figure 4.1 assumes overnight costs of US$ 600/kW for a gas plant and US $5,500/kW for a nuclear plant.[21] The gas plant cost assumption is based on comparison with similar plants built elsewhere. The nuclear plant cost assumption reflects estimates from a pre-feasibility study conducted for Armenia's new plant. However, recent experience has shown the bids for new nuclear costs to be higher than this estimate, with overnight costs ranging from US$ 6,000/kW to more than US$ 10,000/kW. Box 4.1 describes some of the factors that recently have led to cost overruns, and includes overnight cost estimates from recent bids and plants under construction. Appendix G details nuclear plant cost drivers, and includes international examples.

Box 4.1: A Survey of Recent Nuclear Plant Overnight Costs

International industry and government estimates for nuclear construction have ranged from US$ 1,500-US$ 2,100/kW, although recent bids and industry estimates are far higher. The table below shows overnight cost estimates from recent studies.

Source	US$/kW overnight cost
Keystone (2007)	2,950
Constellation Energy (2008)	3,500-4,500
FP&L (2008)	3,108-4,540
Duke Energy (2008)	5,000

The costs of plants under construction are roughly consistent with this range.

Utility	US$/kW overnight cost
Bulgaria – Belene NPP	5,000
Finland – Olkiluoto NPP	3,300
Taiwan – Lungman NPP	3,100

Recent bids suggest that costs may be increasing, in part because of many unanticipated construction delays. Appendix G provides some reasons for delays at the Belene, Olkiluoto and Lungman plants. The table below shows bids for recent nuclear plant construction tenders; all were declined. After the Fukushima accident in Japan, costs are anticipated to rise as costs of safety compliance and insurance also rise.

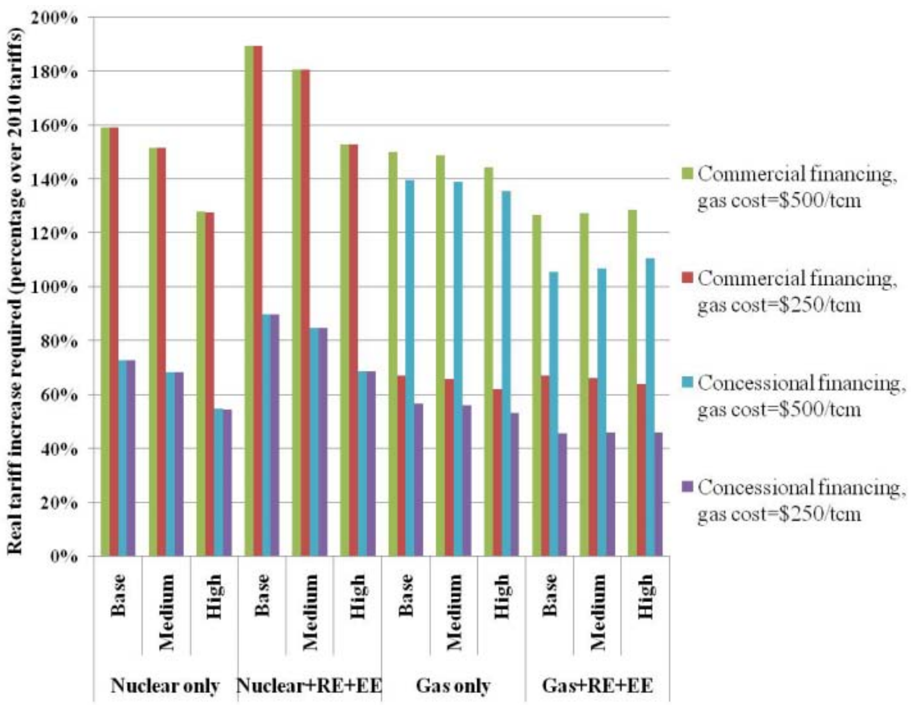
Utility	Vendor	US$/kW
Ontario Power Authority (06/2009)	Atomic Energy of Canada Limited (AECL)	10,800
Ontario Power Authority (06/2009)	Areva	7,375
Electricity Supply Commission of South Africa (2010)	Undisclosed	6,000

Figure 4.3 shows the tariff impact of generation options, under a range of financing, gas prices, and demand growth assumptions (high, medium and base case) shown in Figure 3.2. The Figure shows the real tariff increase required in 2017 under each plant option.

21 Overnight costs include engineering, procurement, and construction, before considering financing and cost escalations.

Ultimately, the Government can decide to limit the tariff shock by smoothing tariff increases over the life of the plant, but the tariff impact rankings for each plant option do not change.[22]

Figure 4.3: Real Tariff Impact of New Capacity Options



The Figure shows the following, consistent with the relationships shown in Figure 4.1:

- The Gas+RE+EE option always has the least tariff impact.
- Gas options generally have lower tariff impacts than nuclear options. However, higher utilization rate, higher gas import prices and concessional financing make the cost of nuclear options increasingly comparable to the costs of gas options.
- EE measures and RE investments increase the cost of nuclear generation because they reduce (EE) or displace (RE) utilization of the nuclear plant. Load factors of the nuclear plant under the base, medium, and high demand scenarios are 62 percent, 65 percent, and 75 percent, respectively. If RE and EE measures are added, the nuclear plant's load factors under the base, medium and high demand scenarios drop to 44 percent, 47 percent, and 59 percent, respectively. As described below, in addition to the cost implications, there are operational and safety considerations that prevent operating nuclear plants at low load factors.

[22] By smoothing the tariff, Government effectively subsidizes consumers. Government can choose to have consumers pay for the cost of the plant over a 50-60 year period, but the plant financiers are likely to expect a quicker return on their investment.

Table 4.1 summarizes and explains the outcomes shown in Figure 4.1.

Table 4.1: Which Types of Plant Have the Lowest Tariff Impact and Why?

<table>
<tr><th></th><th>Base</th><th>Medium</th><th>High</th><th>Explanation</th></tr>
<tr><td>Commercial finance; gas=US$250/tcm</td><td>Gas or Gas+RE+EE (nearly identical)</td><td>Gas or Gas+RE+EE (nearly identical)</td><td>Gas or Gas+RE+EE (nearly identical)</td><td>• Capital costs of gas plant are lowest relative to nuclear, meaning overall debt service and dividend payments are lower
• RE+EE allow the gas plant to run less frequently, reducing system operating costs, thereby reducing the tariff</td></tr>
<tr><td>Commercial finance; gas=US$500/tcm</td><td>Gas+RE+EE</td><td>Gas+RE+EE</td><td>Gas+RE+EE or Nuclear (nearly identical)</td><td rowspan="2">• Capital costs of gas plant are lowest relative to other options, meaning overall debt service and dividend payments are also lower
• RE+EE allows new gas plant to run less frequently, making it more attractive than gas-only option</td></tr>
<tr><td>Concessional finance; gas=US$250/tcm</td><td>Gas+RE+EE</td><td>Gas+RE+EE</td><td>Gas+RE+EE</td></tr>
<tr><td>Concessional finance; gas=US$500/tcm</td><td>Nuclear</td><td>Nuclear</td><td>Nuclear</td><td>• Concessional financing makes the nuclear plant relatively cheaper than under commercial financing</td></tr>
<tr><td>Explanation</td><td colspan="2">Utilization of nuclear plant too low; capital costs of nuclear plant must be spread out over few kWh</td><td>Higher utilization makes nuclear options gradually more affordable relative to gas, if gas price is sufficiently high</td><td></td></tr>
</table>

The analysis above assumes that the Government can find a source of external concessional or private financing for each plant. In addition to tariff implications, public finance implications must be considered. The nuclear plant, using the modest cost estimates in this note, will cost around US$ 6.0 billion, around 64 percent of Armenia's 2010 GDP, and more than triple the cost of a comparably sized gas plant, plus all of the RE+EE options considered in this note. The Government borrowing to finance the new nuclear power plant would increase Armenia's public debt to over 100 percent of estimated 2011 GDP,[23] twice its statutory public debt limit of 50 percent of GDP. The Government borrowing for a new gas plant, on the other hand, would add roughly US$ 700 million to public debt, keeping the public debt to GDP ratio at around 47 percent.

Adequacy of Supply

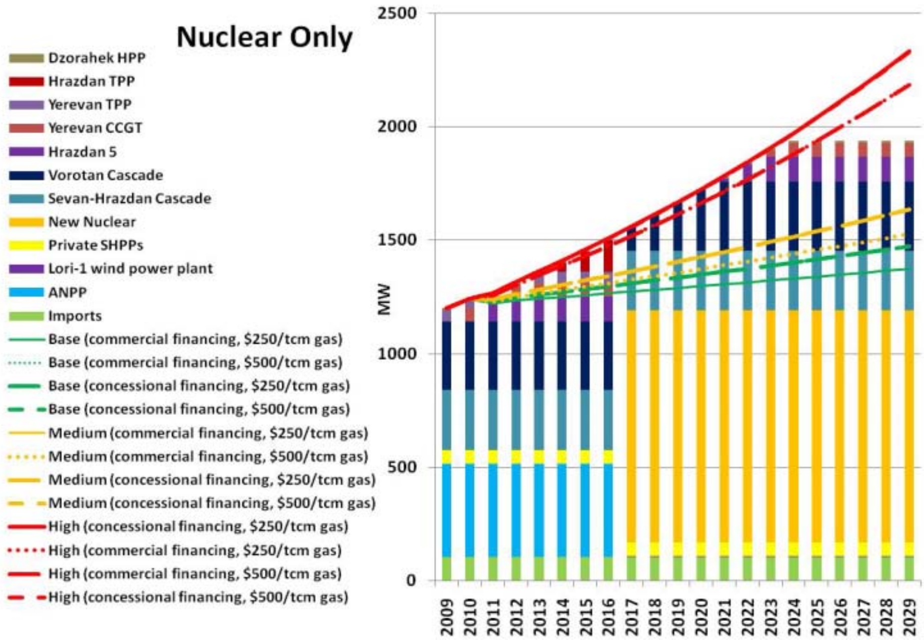
All of the new plant options provide adequate capacity in the base- and medium- demand scenarios. The Gas+RE+EE and Nuclear+RE+EE options provide adequate capacity in the high-demand scenario. Figure 4.4 and Figure 4.5 show how the supply options meet peak demand. [24] Because tariffs are significant determinants of electricity demand (higher real tariffs mean lower demand, and vice-versa), supply adequacy depends on capital costs of the plants, financing terms (concessional or commercial), and gas import price. Therefore, demand forecasts differ by supply option chosen and assumptions about key cost drivers. For example, peak load forecasts for natural gas options are generally slightly higher than for nuclear options.[25]

23 Assuming no other public borrowing takes place.

24 The figures assume Government reduces tariff shock by amortizing plant costs over plant lifetime.

25 Table E.4: Peak Load Forecasts 2011-2029 (MW)Table E.4 in Appendix E tabulates peak load forecasts for all options, under all gas, financing, and load growth scenariosTable E.5: Generation Forecasts 2011-2029: Table E.5 shows the same for annual load (end-use consumption).

Figure 4.4: Adequacy of Supply: Nuclear Options in Meeting Peak



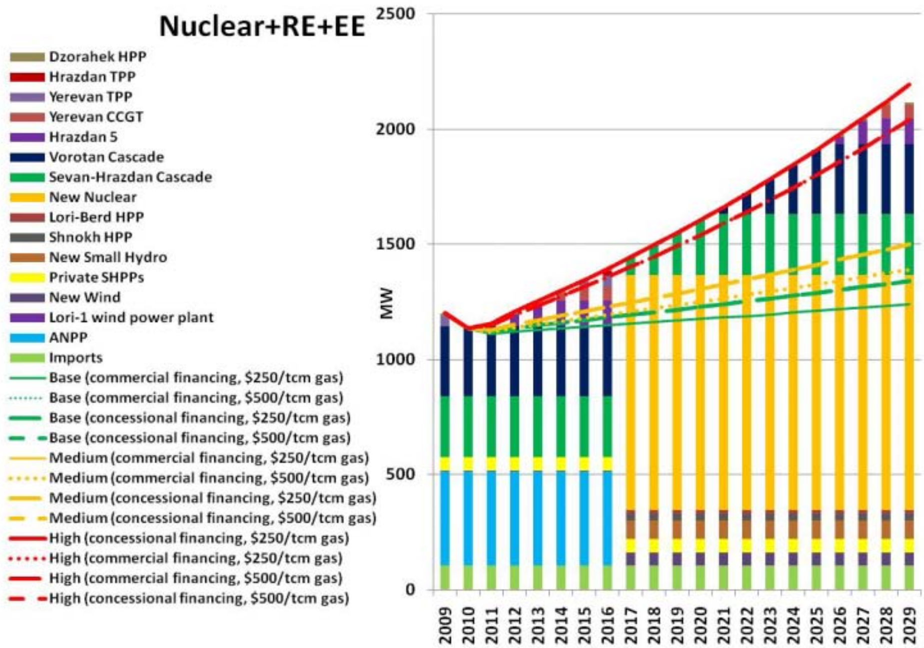


Figure 4.5: Adequacy of Supply: Gas Options in Meeting Peak

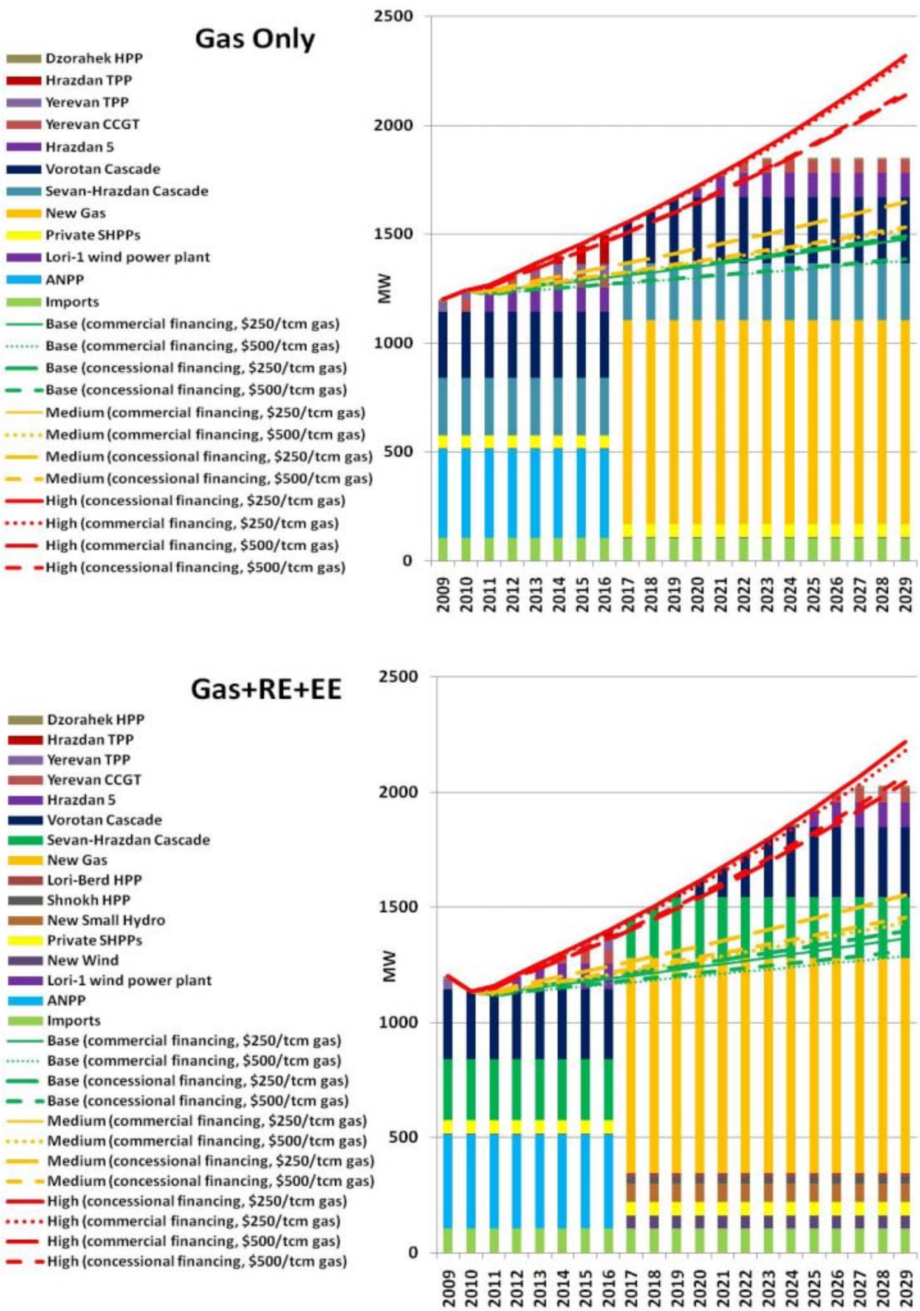
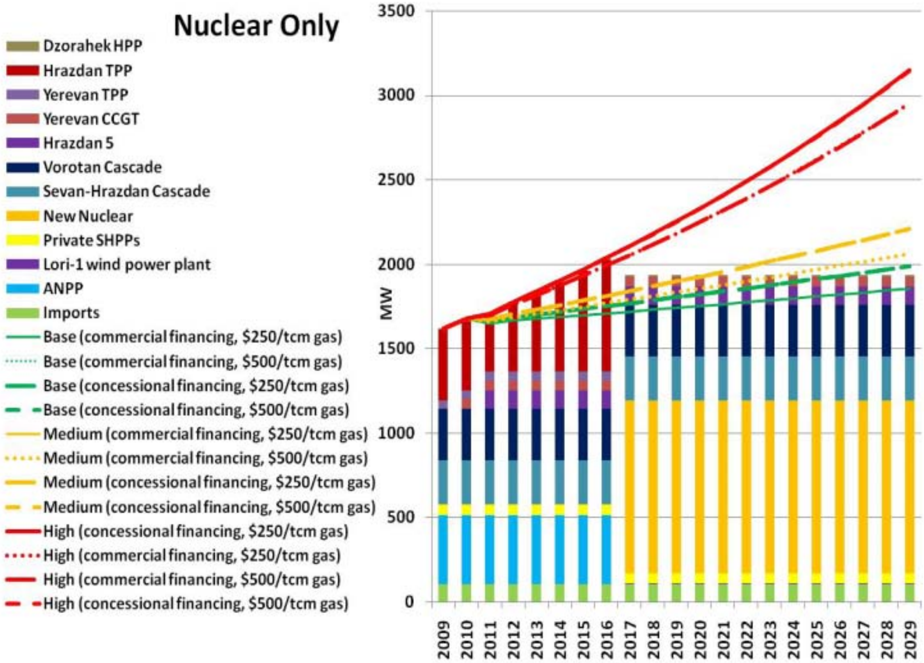


Figure 4.6 and Figure 4.7 show how supply options meet reserve margin. Only one option provides adequate supply in any high-demand scenario: the Gas+RE+EE option with commercial financing and gas costs of US$ 500/tcm.

In the above figures, nuclear options exhibit a steeper curve than gas because they require higher reserve margins than other plant options to ensure system reliability. An approximate benchmark of system reliability calls for generation capacity sufficient to meet peak demand when the largest generating unit is lost. The analysis in this paper assumes that a 35 percent reserve margin is required if a new nuclear plant is built. In practice, the reserve margin required may be higher, given the large size of the plant relative to the Armenian system. A rough proxy for N-1 supply reliability is to have a reserve margin equal to the available capacity of the largest single unit on the system. In other words, if the largest single unit stops operating, a reserve margin of the same capacity would be needed to meet peak demand. It is our understanding that the nuclear plant will be a single unit with 1,100 MW turbine, which reportedly allows significant flexibility in adjusting the operating capacity of the plant.

Figure 4.6: Adequacy of Supply: Nuclear Options in Meeting Reserve Margin



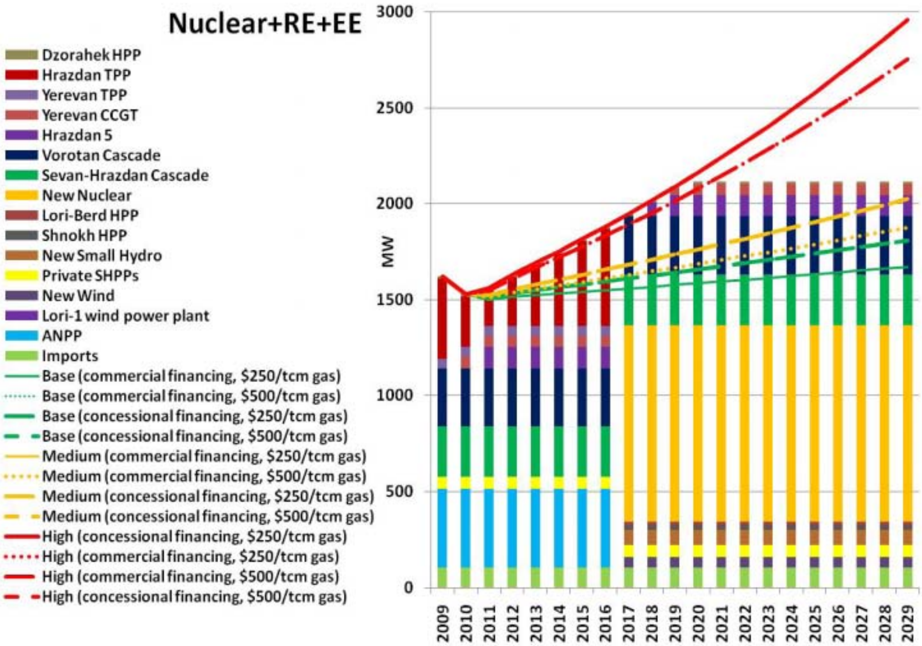
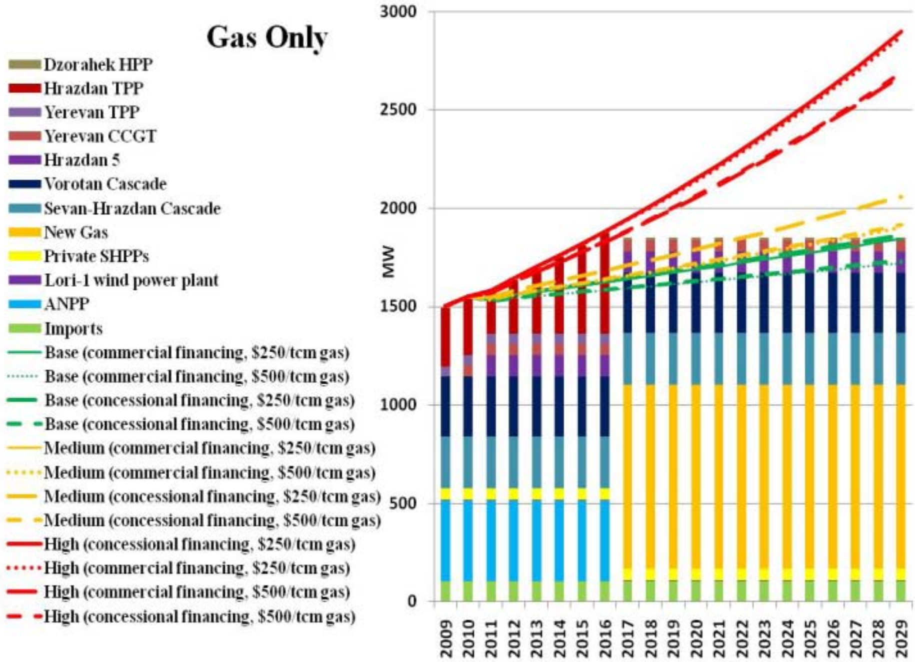


Figure 4.7: Adequacy of Supply: Gas Options in Meeting Reserve Margin



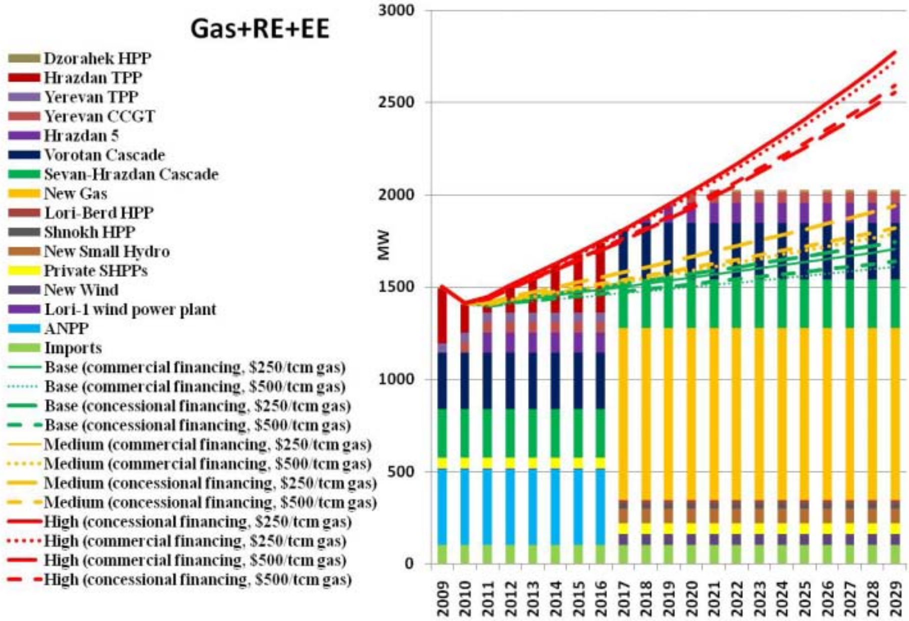
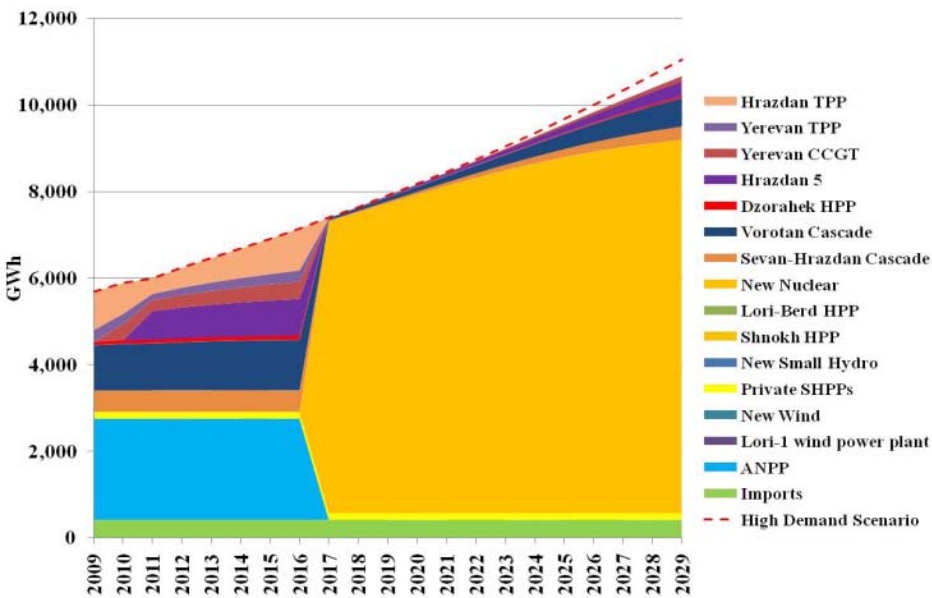


Figure 4.8 shows the generation gap estimated to emerge under the highest demand scenario and lowest supply option (Nuclear-only, concessional financing, with a gas cost of US$ 250/tcm). Under this scenario, a small generation gap emerges in 2017 (roughly 275 GWh), and gradually grows.

Figure 4.8: Generation Gap: Nuclear-Only Scenario



Clearly, the nuclear option clearly provides adequate supply in many of the demand scenarios, but there are two other important considerations that influence supply adequacy:

- **The nuclear options are more difficult to implement under lower demand scenarios.** Nuclear plants are meant to be run as baseload plants, generating at relatively high capacity factors when they are in service. Running nuclear plants at lower capacity factors can be hazardous and costly, as described in the previous section.[26] In the low- and medium- demand scenarios, it would likely be necessary to back down other, lower cost, generating capacity in order to operate the nuclear plant safely. Even in the high demand scenario, the nuclear plant would likely have to displace some of the less expensive hydroelectric and gas units during off-peak hours in order to operate at safe levels. Backing the nuclear plant down substantially, instead of other plants, is more difficult from a technical perspective, and is less advisable economically given the low costs of operating a nuclear plant once it is built.
- **The nuclear plant takes longer to build.** When considering supply adequacy, it is important to take into account the time required for construction of a new plant. Nuclear plants typically require a minimum of 5-6 years for construction, whereas gas plants can be built in 3-4 years. As shown in Box 4.1 and Appendix G, the risk of delays is substantially higher for nuclear plants and those delays lead to cost increases.

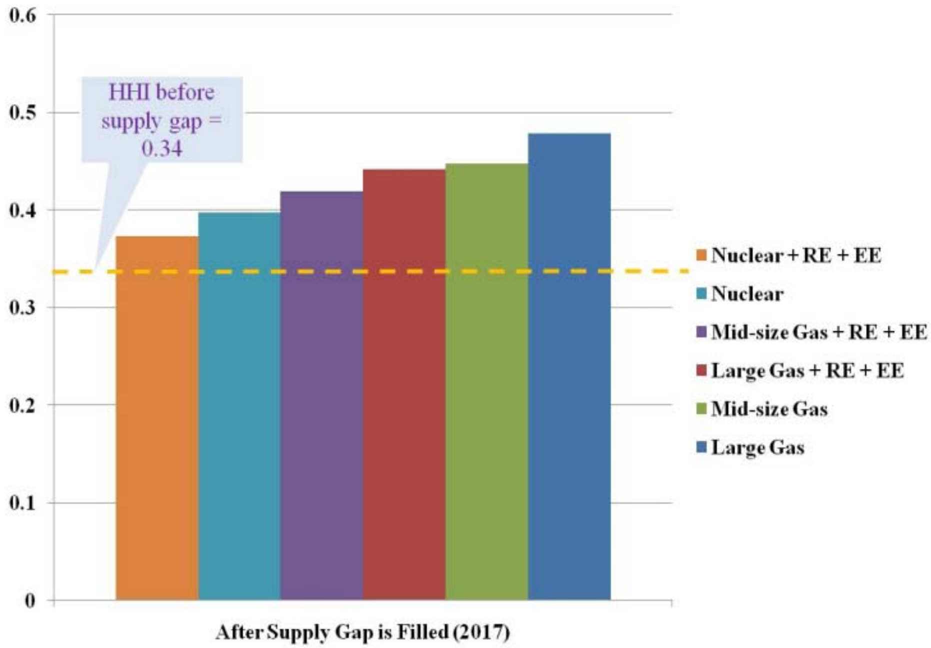
Diversity of the generation mix

Armenia has better supply diversity now compared to any of the options for new capacity. The nuclear plant provides better supply diversity than a new gas plant. Supply diversity of either the nuclear or gas option can be improved by adding renewable generation capacity and energy efficiency. If RE + EE is added, the nuclear and mid-sized gas plants are nearly identical in terms of supply diversity. The Figure 4.9 compares the Herfindahl-Hirschman Index (HHI) for different supply options by fuel type.[27] A lower HHI implies greater supply diversity. The figure also suggests that a right-sized (800 MW) gas plant provides better supply diversity than a larger one.

[26] This report does not take any view on the safety implications of building or operating a nuclear plant in Armenia.

[27] A measure of the size of firms in relation to their industry and an indicator of the amount of competition among them. HHI is used to measure market concentration of different companies. A lower HHI means greater diversity of supply. The HHI is typically calculated as the sum of the squares of each firm's market share. This analysis uses HHI as a proxy for the diversity of fuel supply for electricity generation, and calculates "market share" as percentage of generating capacity using each particular fuel type (hydro, nuclear, gas, wind, and imports). In this case, operable capacity is used to measure market share.

Figure 4.9: Using HHI to Assess Energy Supply Diversity[28]



4.2 Energy Security

Section 4.1 described how security of supply can be improved by maintaining diversity in fuels used to generate electricity. Armenia's energy security can be further enhanced through:

- Rehabilitation of electricity transmission and distribution infrastructure, and
- Investments in petroleum and gas storage.

Each of these solutions is discussed in more detail in the following subsections.

Rehabilitation of electricity transmission and distribution infrastructure

The transmission company, the High Voltage Network of Armenia (HVEN), and the distribution company, the Electricity Networks of Armenia (ENA), can reduce technical losses, and improve reliability and quality of supply by rehabilitating their networks. Network losses total 13 percent of gross supply in Armenia.

[28] The figure does not reflect capacity of plants with output destined for export (Hrazdan 5, Yerevan CCGT and Meghri HPP).

HVEN has undertaken rehabilitation of the transmission system over the past ten years with the help of development partners. A €14.1 million loan from KfW was used to overhaul the transformer stations in Kamo, Vanadzor and Alaverdi. From 1999 to 2006, the Electricity Transmission and Distribution Project, financed by the World Bank, provided US$ 19.8 million to rehabilitate transmission substations. Despite these investments, HVEN estimates that roughly 20 percent of its lines and pylons (roughly 520 km) are in need of urgent rehabilitation, at an estimated cost of roughly US$ 80-100 million.

ENA has also embarked on an ambitious investment plan. It planned to invest US$ 164 million in 2011-2013 to reduce losses, improve quality of supply, and improve energy system integration programs with other CIS countries.

In total, roughly US$ 300 million required in new transmission and distribution investments planned will add an extra AMD 2/kWh to tariffs.

Investments in gas and petroleum storage

Increasing gas storage capacity can improve the security of short-term gas supply. Armenia has suffered a number of supply interruptions on the gas pipeline that runs through Georgia. In 2009, Armenia had 127-130 million m^3 available gas storage capacity, securing around 10 days of gas supply during the winter peak consumption. In 2010, Armrusgazprom invested US$ 1.6 million to increase its capacity to 140 million m^3.[29] It has plans to further increase capacity to 190-195 million m^3 of gas by 2013. These investments would increase the amount of time Armenia could rely on its natural gas reserves by as much as 50 percent.

There is also a possibility that Armenia's underground gas storage facilities could be converted to a strategic petroleum reserve. A World Bank desk study identified three alternatives for the location of a strategic petroleum reserve: rail cars, above-ground tanks, and underground gas storage facilities. Table 4.2 demonstrates the pros and cons of each alternative. A more detailed feasibility study will need to be conducted to identify the appropriate solution.

[29] "Armrusgasprom`s investments in Armenia`s gas sector $28 million last year". News.am. April 11, 2011. (http://news.am/eng/news/54735.html). Accessed on May 5, 2011.

Table 4.2: Strategic Petroleum Reserve Alternatives

Option	Advantages	Disadvantages	Storage Capacity (in Days)	Estimated Cost (USD/liter)
Rail cars	Low cost, operational flexibility, country- wide distribution	Limited reserve capacity, possible rail line congestion	10	0.0015
Above-surface tank	Adequate capacity for Yerevan through 2020, use of commonly constructed facilities	Fairly high-cost alternative, fewer benefits to markets outside of Yerevan	50	0.022
Underground gas storage	Potentially lower cost than other alternatives, most secure alternative, highest expansion potential	Unknown suitability of site and its availability for storage of other products than natural gas.	~10 (assuming 140 mln m^3 of storage)	Unknown, too many unknowns about suitability and availability of site

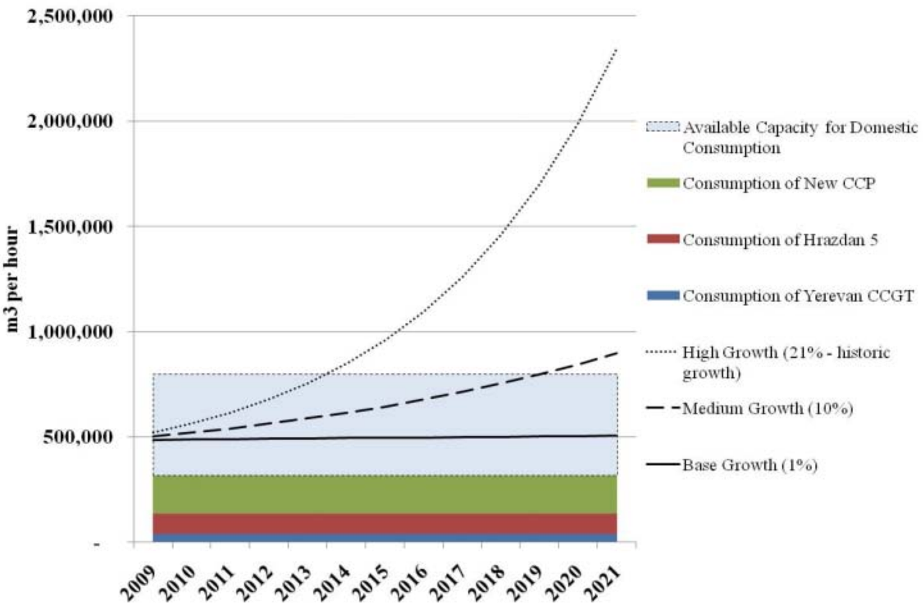
Source: World Bank. Strategic Petroleum Reserves in Armenia, November 2008.

Utilization of domestic resources

As shown in the previous section, the generation options that include RE+EE improve supply diversity. These options are also better for supply security since they reduce Armenia's exposure to possible fuel supply disruptions. Armenia imports its nuclear fuel from a single source and all natural gas comes through Armenia's pipeline links to Georgia and Iran. With new Hrazdan 5 and Yerevan CCGT plants in operation, fuel destined for Armenia's new gas plants will compete for pipeline capacity with consumption for residential heating and industrial use.

If natural gas consumption were to continue to grow at its 5-year historic average rate of 21 percent per year (excluding consumption by the electricity sector), the capacity of Armenia's gas pipelines would be exhausted as early as 2016. However, gas demand is not likely to continue to grow at this rate, since due to Armrusgazprom's expansion over the past 5 years, roughly 80 percent of the population now has a gas connection. Armrusgazprom forecasts its average annual gas consumption to grow at 0.9 percent per year in the coming few years, meaning Armenia's remaining pipeline capacity could easily sustain a large gas plant well beyond 2030 (assuming no other new gas plants are built during that timeframe). The Figure 4.10 presents the above analysis in a graphical form.

Figure 4.10: Gas Pipeline Utilization and Possible Constraints



Armenia might consider using more of the new Hrazdan 5 and Yerevan CCGT capacity for domestic electricity generation rather than export. An economic justification would depend on the monetized price of Iranian gas used in the swap: if it is higher than alternative gas supply sources, the least-cost option might be to run Hrazdan 5 and Yerevan CCGT for domestic use, rather than build new gas plants.

4.3 Affordability

Tariffs can be kept affordable by:

- Improving Armenia's electricity system load factors through energy efficiency measures or exports.
- Improving the plant factors of plants with lower variable costs through the use of pumped storage.
- Providing earmarked energy subsidies to low-income customers through the PFBP or some similar targeting mechanism.

Improving the load factor

Armenia can reduce its need for new generating capacity, and hence overall cost of new generating capacity, by improving the system load factor. The system load factor is the ratio of average consumption to a system peak during a given time period. The load factor can be improved by increasing average consumption relative to peak or reducing peak demand relative to baseload.

Armenia's historical load factor ranged between 50 and 60 percent. Many advanced electricity systems gravitate toward load factors that range from 60 to 70 percent. As Figure 4.1 and Figure 4.2 illustrate, improving the capacity factor of plants increases their utilization (capacity factors) and lowers their LEC, which can lower the average system costs. Armenia has several options for improving its load factor.

First, Armenia can improve the overall system load factor by exporting more electricity during off-peak periods (for example, during the summer months or during off-peak periods in summer or winter).[30] This will increase baseload relative to peak, thereby increasing utilization of the nuclear plant. In the short-term, Armenia's electricity exports will likely continue to be competitive. In the long-term, however, Armenia's electricity producers may have difficulty increasing exports because the region has a number of other competing suppliers with lower cost supplies of energy. Box 4.2 contains a more detailed analysis of Armenia's potential to become an exporter to the region.

[30] As noted in earlier sections, Armenia already has some regional exchange of electricity with Iran and Georgia.

Box 4.2: Armenia's Potential for Electricity Exports

Beyond the short term, Armenia's electricity producers may have difficulty exporting to the region given the competition against multiple lower-cost energy suppliers.

A new 500 kV transmission line planned between Azerbaijan, Georgia and Turkey would allow Turkey to absorb surplus from Azerbaijan and Georgia in summer. Export prices from Armenia will likely be higher than the estimated export prices for electricity from Azerbaijan and Georgia. Azerbaijan has its own oil and gas resources and Georgia has an abundance of cheap hydroelectric generating capacity (85 percent of Georgia's electricity is generated by hydroelectric plants). Azerbaijan is expected to be able to offer electricity to Turkey at roughly US$ 0.07/kWh in 2015. Georgia is expected to offer prices ranging from US$ 0.06/kWh -0.07/kWh.

Armenia's average system generating cost will likely be in the range of US$ 0.06/kWh - 0.15/kWh, depending on demand growth and the cost of financing for each plant (the nuclear plant in particular). However, the average system cost understates the likely export costs to Turkey because the average system cost refers to the cost of electricity before delivery (in other words, excluding transmission costs) and because countries will typically serve domestic load with their lower cost plants and export electricity from their higher cost plants.

In the short-term, Armenia's exports will likely continue to be competitive with Azerbaijan and Turkey, and Armenia will continue to have an electricity surplus. The global financial crisis has delayed the threat of a demand gap in many of the countries in the region, but some opportunities for seasonal exchange of electricity will still exist. Armenia's older plants operate at relatively low cost because from a tariff perspective they are fully depreciated and no longer receive a capacity charge. Moreover, Armenia imports gas from Russia at much lower prices than other countries. Therefore, Armenia's average generating costs are competitive with its neighbors and, in particular, are currently much lower than in Turkey. Armenia's average cost of generation is roughly US$ 0.035/kWh-0.045/kWh. The average cost of generation in Turkey is around US$ 0.073/kWh, in Azerbaijan – US$ 0.03/kWh, and in Georgia – US$ 0.015/kWh.

Sources: Econ Poyry AS. "Electricity Export Opportunities from Georgia and Azerbaijan to Turkey." Commissioned by the Ministry of Energy of Georgia.

Fichtner. "Regional Power Transmission Extension Plan for Caucasus Countries." Final Report for KfW. November 2007.

Public Services Regulatory Commission, Armenia.

Second, Armenia can improve its load factor by using EE measures to reduce peak load. A 2008 World Bank study estimated that Armenia could save as much as AMD 132 billion annually, or about 4.95 percent of its 2006 GDP, by making EE investments recommended by the National Program on Energy Savings and Renewable Energy.[31] Box 4.3 summarizes the study results.

[31] The 2008 study did not consider the possibility that Armenia would build a nuclear plant with more capacity than needed to serve peak load. Section 4.1 shows that EE measures could increase cost per kWh of electricity if the already low utilization of a large nuclear plant is further reduced (because capital costs are spread over fewer kWh). The EE measures would add to overall costs in a system that already has surplus capacity.

Box 4.3: Energy Efficiency Investments in Armenia

A 2008 World Bank study on EE identified economically and financially viable investments in EE in all sectors. Not surprisingly, sectors with the largest potential savings are those with highest energy consumption volumes—building heating, transport, and utilities. Below is a summary of study results.

	2005 Consumption	Technical Potential for Savings	Value of Technical Potential	
Sector	*(mtoe)*		*(million AMD)*	*% of Armenian 2006 GDP*
Industry	0.41	0.04	8,581	0.32
Public sector	0.04	0.01	1,110	0.04
Households	0.50	0.08	13,159	0.49
Utilities	0.62	0.52	45,831	1.72
Transport	0.44	0.01	3,233	0.12
Buildings (heating only)	1.12	0.53	60,274	2.26
Total	3.12	1.21	132,189	4.95

Armenia can save about 1 TWh of electricity and 600 million m^3 of natural gas through technically viable investments; around 97 percent of reductions can be achieved through investments that are both economically and financially viable. In terms of energy content (mtoe), about 85 percent of energy savings results from implementing measures that conserve natural gas (.51 mtoe), and 15 percent from measures that conserve electricity (.09 mtoe).

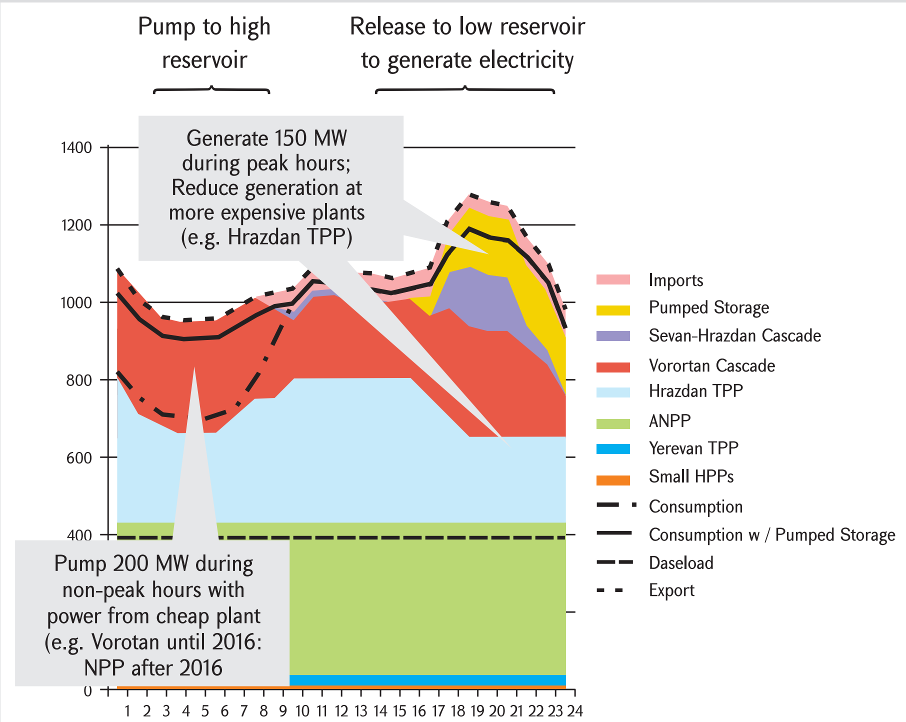
The study revealed that public sector EE investments have the highest return on investment, followed by the industrial sector, households, and utilities.

Source: World Bank. The Other Renewable Resource: The Potential for Improving Energy Efficiency in Armenia. July 2008.

Finally, Armenia can improve its plant factors by utilizing pumped storage on its existing hydro cascades. Pumped storage can improve plant factors of nuclear or other plants with low variable costs by using spare capacity to pump water back up into higher reservoirs during off-peak hours. The pumped water can be stored and used to generate electricity when needed to serve system peaks. Box 4.4 analyzes how pumped storage could work in Armenia.

Box 4.4: Benefits of Pumped Storage in Armenia

Pumped storage can reduce generation costs during peak hours. Pumped storage plants use electricity to pump water into a higher reservoir when demand is low and electricity is inexpensive. Plants can then generate electricity when demand is high and power is expensive. The figure below shows how Armenia could use pumped storage (on a typical winter day) to balance daily load at lower cost. If Armenia builds a new nuclear plant, implementing pumped storage would enable to improve demand reliability and increase capacity utilization during off-peak hours.



A preliminary technical feasibility study commissioned by the Armenia's Renewable Energy and Energy Efficiency Fund identified three potential sites.

- Hrazdan River with the Aghbara Reservoir serving as the lower basin,
- Sisian River with the Tolors Reservoir serving as the lower basin,
- Vorotan River with the Shamb Reservoir serving as the lower basin.

A detailed feasibility study is needed to determine the best option.

Source: World Bank.

Providing consumption subsidies to low-income households

A substantial increase in end-user tariffs is likely to make electricity and gas consumption unaffordable for a growing proportion of Armenian households. However, the financial sustainability of the sector requires the tariffs to keep pace with anticipated cost increases. There are a number of measures the Government can consider to make electricity affordable for low-income customers, while preserving the financial sustainability of the sector.

Designing a subsidy program requires decisions about:

- **Identification of low-income customers.** Armenia has a well-established social support program, the PFBP, which provides direct cash transfers to poor households. Households are identified as poor according to a formula with thirteen means-testing variables. The PFBP's family vulnerability assessment includes a formula which measures energy poverty.

  As an alternative, customers could be identified based on their energy consumption. So-called lifeline tariffs are tariffs set below the cost of service for some minimum level of energy consumption (for example, 50 kWh and less). Consumers must pay higher (cost recovery) tariffs for any units of energy consumed beyond the minimum lifeline volume. On the one hand, lifeline tariffs allow for only very rough targeting of customers. Customers who use less than the lifeline volume may not be poor (for example, individuals with vacation homes). Customers who use more than the lifeline may not be wealthy (for example, households with many family members). On the other hand, if the poverty rate is high (as it is in Armenia) or the accuracy of alternative targeting mechanisms is low, lifeline tariffs may be the best option.

  The Government does have some experience with lifeline tariffs. Lifeline tariffs were used in the electricity sector in the 1990s. Moreover, in March of 2011, the Government introduced a temporary, one-year lifeline tariff for natural gas customers. However, the low-income customers of electricity and gas service require longer term support.[32]

- **Delivery of the subsidy.** Subsidies can be delivered directly to customers, as cash or vouchers, or indirectly, as discounts on customers' energy bills. The Government could deliver the subsidies directly, through the PFBP, or indirectly, by discounting tariffs for certain customer classes or (as with a lifeline tariff) certain volumes of consumption. If the Government decides to use the targeting mechanism used by PFBP, it could consider using vouchers instead of cash to ensure that the subsidy is spent on energy.

- **How to fund the subsidy.** Subsidies may be funded by direct transfer from the Government (to the utility or to the PFBP program), or through cross-subsidies by other customers. Lifeline tariffs are more commonly funded through cross-subsidies. The advantage of a cross subsidy is that it avoids using government funds.

32 Under the current gas lifeline tariff, poor customers pay AMD 100/m^3 compared to regular tariff of AMD 132/m^3. This tariff holds for up to 300 m^3 of gas consumed during the 1-year period from April 1, 2011 until March 31, 2012.

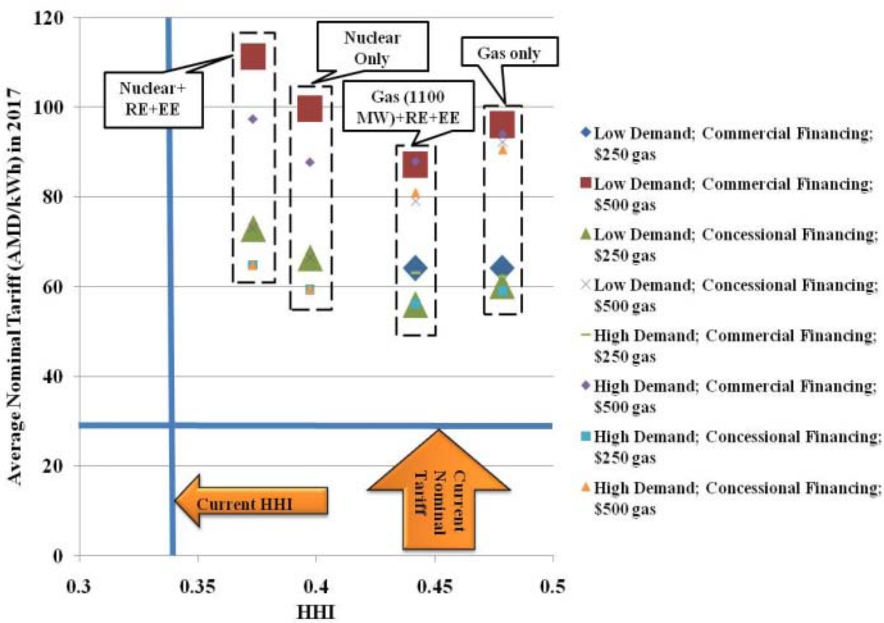
The disadvantage is that it distorts prices, and therefore will distort consumption by the customer classes that fund and receive the cross subsidy.

4.4 Summary

The analysis above illustrates that generating options involve substantial tradeoffs. If demand grows within the base and medium ranges, building a new nuclear plant poses a risk of overcapacity for which Armenian customers will have to pay.[33] If demand resembles the high-demand scenario, system planners will need to evaluate options for adding around 1,100 MW by 2017.

Figure 4.11 illustrates the tradeoffs between cost of supply and supply diversity. It is clear that Armenia is on the brink of a paradigm shift in terms of supply diversity and cost of supply. It cannot do better than it currently does in terms of supply diversity and cost. Nevertheless, some options are clearly better than others, depending on what the Government believes will happen with gas costs, and what financing it believes will be available for construction of new plants. The possible tariffs range from AMD 56/kWh (USD 0.14/kWh) for a 1,100 MW Gas +RE+EE option (under the assumption of low gas prices, low demand, and concessional financing) to AMD 111/kWh (USD 0.30/kWh) for the Nuclear+RE+EE option (under the assumption of low demand and commercial financing).

Figure 4.11: Tradeoffs - Cost and Supply Diversity



33 If not the current customers, than future customers or taxpayers who provide the government with revenue that it would have to use for electricity subsidies.

The Government likely has some certainty with respect to future gas prices and availability of financing, but the path of economic growth, a key driver of electricity demand, is much more difficult to predict.

The high-demand case of 11 percent annual GDP growth seems unlikely, but during 2010 Armenia's electricity demand growth was 3.0 percent suggesting rapid recovery from the global financial crisis. Demand might continue to grow at pre-crisis rates.

There is also considerable uncertainty surrounding the costs of new units. The cost-effectiveness of the new nuclear plant is very sensitive to capital costs. Even before the events at Fukushima in April 2011, construction costs and construction timeframes for new nuclear plants were difficult to predict. This unpredictability will likely continue as suppliers adjust to the changes of the market.

With such uncertainty, a staged approach is advisable. There seems to be little question that the Government will proceed with its plans to build a nuclear plant, but the Government also recognizes that the plant might not be ready by the earlier target date of 2017.

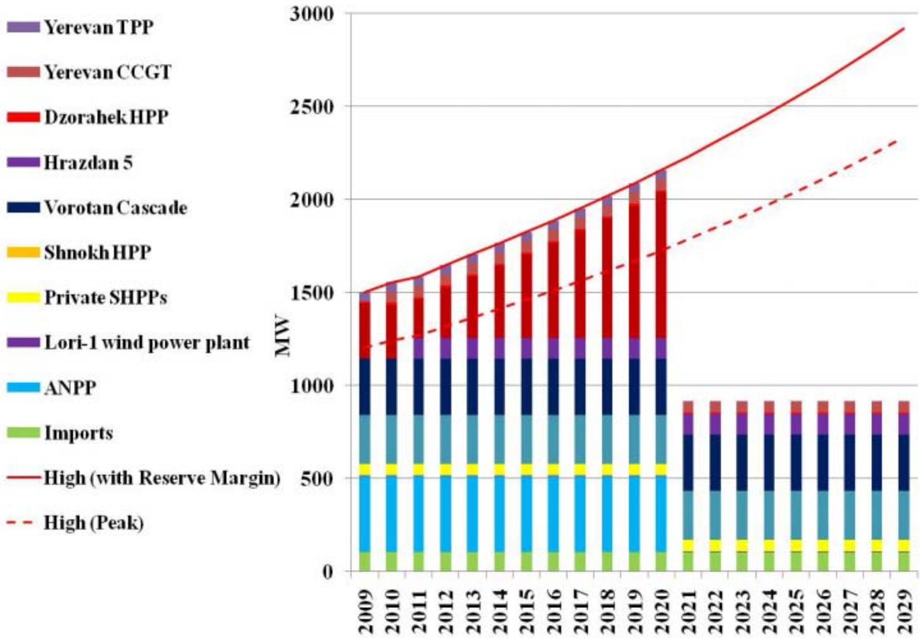
In the interim the Government could consider the construction of smaller gas units (200-300 MW each) and investments in EE measures and RE generation as described above. Gas plants can be built in smaller increments and more quickly, offering some flexibility to respond to changes in demand. If within the next several years the nuclear option becomes more difficult or demand comes close to the high-demand scenario range, more gas plants could be built. On the other hand, if demand appears to more closely track the low-demand scenario, less new gas capacity might be sufficient. A smaller gas plant, for example 600 MW, is more affordable and offers better supply diversity than the larger 800 MW and 1,000 MW "right sized" gas plant options described above.

The use of additional capacity at Hrazdan 5 or Yerevan CCGT could also be considered, rather than using these plants entirely for export. The Government could also consider reserving some or all of the capacity of the planned Meghri HPP for domestic use rather than (as currently planned) export to Iran.

Delaying retirements may also be part of the solution, provided these could be done given safety and operational considerations.[34] Figure 4.12 shows that, even under the highest demand scenario, Armenia's electricity system could continue to meet peak and have nearly enough reserve capacity. Some of the thermal plants could conceivably be retired in 2017, as scheduled, if a new, mid-sized gas could be built in the meantime.

[34] This note does not take any view on the safety considerations of delaying the shutdown of the Metsamor nuclear power plant.

Figure 4.12: Delaying Retirement (Metsamor NPP, Hrazdan TPP and Yerevan TPP)



The choice of generation options, plus sequencing, and financing those options are the most difficult challenges facing the Government. Other recommendations in this section follow from that choice.

As noted above, energy security can be enhanced by continuing rehabilitation of electricity transmission and distribution infrastructure and increasing gas (and possibly petroleum) storage capacity. The impact of a tariff increase can be mitigated through measures that improve the overall system load factor in Armenia and by considering an additional cash transfer in the PFBP to cover higher energy costs.

Appendix A: History of Energy Sector Reforms in Armenia

Armenia underwent major reforms of its power sector after a severe electricity crisis that began with the dawn of Armenia's independence from the Soviet Union. The World Bank provided important support to the reforms. This Appendix discusses the steps Armenia took to reform the sector, why reform was necessary and how the World Bank worked with the Government to implement a successful reform of the sector.

A.1 Why Reform was Necessary

Post-Soviet Armenia gained independence, but faced serious challenges similar to those in other former Soviet republics. Armenia's electricity system was not autonomous; it had been developed as part of a much larger Trans-Caucasus electrical grid. Armenia relied heavily on imported fuel from neighboring countries and the problems with this system began to show in 1992.

The start of the war over Nagorno Karabakh and the resulting economic blockade by Azerbaijan and Turkey cut off Armenia's only source of gas and oil for its thermal plants. Four years prior to that, a massive earthquake had forced a shut-down of the Metsamor NPP, a source of roughly one-third of Armenia's generating capacity. Supply from a new gas pipeline, built in 1993 through neighboring Georgia, was regularly interrupted by acts of sabotage. Armenia was left to rely almost entirely on its hydropower resources, at great expense of Lake Sevan, one of the country's most precious natural resources. Between 1992 and 1996, customers suffered through several of Armenia's brutal winters with little more than two hours of electricity per day.

Fiscal and quasi-fiscal subsidies to the power sector had reached a level of roughly 11 percent of Armenia's GDP by 1995 (the first year when reliable data are available). Collections were around 50 percent, and nearly 25 percent of all power produced disappeared before the meters as commercial losses (mostly electricity theft). The system remained dilapidated from years of crisis operation and underinvestment and was dependent upon massive public subsidies.

A.2 Steps Taken for Reform

Major reforms in the Armenian power sector included the following.

- Unbundling and privatizing the power system
- Establishing an independent regulator
- Achieving sectoral financial sustainability.

The following subsections describe these three reform efforts in detail.

Unbundling and Privatization

By March 1995, efforts began on unbundling the power system and privatizing the power sector; Armenergo, the state-owned vertically integrated utility, was separated into generation and distribution entities. In March 1997, a Presidential Order and new Energy Law formalized separate generation, distribution, transmission and dispatch.

Box A.1: Privatization of the Distribution Network in Armenia

The 1997 Law on Privatization provided the legal foundation for the privatization of the power sector in Armenia. Gradually, between 1997 and 2002, privatization of 25 small hydropower plants took place. However, privatization of the distribution network proved to be more challenging. Appendix A describes Armenia's multi-step process of privatizing its distribution network.

The process of privatizing the distribution network began in 1998 when the Government of Armenia hired transaction advisors. Prequalification documents were issued in late 1999, and by early 2000 five major international energy companies had expressed interest. Four of those companies prequalified, but none submitted bids by the April 2001 deadline. This was due to flaws in the tender documents and legal framework.

The Government of Armenia revised the tender documents and appointed new transaction and legal advisors. The GOA also revised the Energy Law to reduce potential government interference in sector operations. A second tender was held in 2001, but failed as a result of world events at the time. In 2002, Midland Resources Holding, a purely financial investor, presented an offer for the company. Although initially viewed with caution due to MRH's lack of experience in electricity operations, the Government of Armenia proceeded with discussions with the company. MRS eventually assumed ownership of the distribution in the fall of 2002.

Source: Sargsyan, Gevorg, Ani Balabanyan, and Denzel Hankinson. "From Crisis to Stability in the Armenian Power Sector." World Bank Working Papers74 (2006).

During 2002-03, ownership of several major generating plants was transferred from the Government in exchange for US$ 96 million in state debt forgiveness (see Table A.1).

Table A.1: Ownership Transfer of Major Power Plants in Armenia

Generation Plant Name	*New Owner*	*Amount of Debt Forgiveness*
Hrazdan TPP	Russian Federation	US$ 31 million
Sevan-Hrazdan Cascade	RAO "Nordic"	US$ 25 million
Metsamor	Inter-RAO UES (financial management only)	US$ 40 million

Establishment of the regulator

The Presidential Order and the Energy Law enacted in 1997 established an independent energy sector regulator, the Armenian Energy Regulatory Commission (AERC). The Law on the Regulatory Body for Public Services, enacted in 2004, changed the name of the regulator to the Public Services Regulatory Commission (PSRC) and expanded its authority to other sectors, including water, drainage and sewage, and telecom. Appendix B describes the functions of the PSRC in further detail.

Financial sustainability

Three steps were essential to increase collections, reduce commercial losses and improve the overall financial sustainability of the sector. These included:

- **Installing meters.** Between 1997 and 1998, twelve thousand new tamper-proof meters were installed throughout the power system at a variety of voltage levels down to 0.4 kV. Residential customer meters were relocated to public areas. An Automated Metering and Data Acquisition System (AMDAS) was installed in 2001 and linked to a settlement center to facilitate accurate meter reading at the 110 kV and above
- **Bringing tariffs to cost recovery levels.** In 1994, Armenia began a gradual transition to cost-based tariffs by bring household tariffs to the average level of other retail tariffs. A schedule was established for further household tariff hikes. Since 1999, household tariffs have remained well above the overall average tariff
- **Increasing transparency in collections and billing.** The Electricity Distribution Company (EDC) installed a computerized customer information system to better track utilization and billing. In 1999, the EDC established a new collection scheme requiring bill payments at post offices instead of cash payments at local EDC offices, which reduced opportunities for collusion between customers and EDC inspectors.

A.3 The Role of the World Bank

The World Bank worked closely with the Government and sector stakeholders to shape key measures that were critical to the sustainability of the reform process. Key instruments that were critical to the effectiveness of the World Bank strategy in the sector include:

- The mixture and sequence of loans provided. The World Bank utilized two loan arrangements in support of power sector reforms in Armenia. Structural Adjustment Credits (SAC) I-IV influenced sector reforms via the following key conditions:
    - Improvement of collection rates;
    - Increased tariff levels to cover operating costs;

- Development and implementation of a comprehensive financial rehabilitation program;
- Development and implementation of a privatization strategy.

The World Bank also provided sector-specific investment loans to emphasize cost-effective rehabilitation of the existing power system, as opposed to immediate investment in costly new infrastructure.

- Technical assistance. The World Bank provided technical assistance to help the Government defend its rationale for supporting consolidation and cost-effective reform of the existing power system. For example:
    - A World Bank study influenced the Government's decision to focus first on the areas of most significant commercial losses at a cost of US$ 20 million, (solving 60 percent of the problems with commercial losses), rather than investing US$ 80-100 million immediately to solve 100 percent of commercial losses;
    - The World Bank emphasized the cost effectiveness of meter relocation over complete meter replacement.

Appendix B: Overview of the Regulatory Framework

The 1997 Energy Law established the current regulatory framework for the energy sector in Armenia. This section provides an overview of the regulatory framework and describes how the Government has built upon the existing framework. Section B.1 begins with a general overview of regulation of the electricity sector. Section B.2 continues by describing the development of renewable energy regulation. Section B.3 outlines the tariff setting methodology. Section B.4 concludes with a description of the service quality standards.

B.1 Regulation of the Electricity Sector

The 1997 Energy Law is the foundation for electricity sector regulation in Armenia. The Energy Law established the Armenia Energy Regulatory Commission (AERC) as an independent regulator responsible for technical and economic regulation. In 2004, the Law on the Regulatory Body for Public Services renamed the AERC as the Public Services Regulatory Commission (PSRC) and expanded its regulatory responsibilities to include the water, natural gas, and heating sectors. In 2005, an amendment to the Law on the Regulatory Body for Public Services gave the PSRC regulatory responsibility for the telecommunications sector.

The Energy Law sets the functions and operational procedures of the regulator for the electricity sector. According to the Law, the regulator's responsibilities include:

- **Issuing licenses**. All generation, transmission, and distribution operators must obtain a license from the PSRC. The PSRC sets conditions for obtaining a license and has discretion over all procedures and terms of the licensing application process
- **Setting tariffs**. The PSRC sets and reviews tariffs for generation, transmission, dispatch and distribution
- **Overseeing compliance with licensee obligations**. The PSRC reviews the operation of licensees and can penalize operators for not fulfilling license requirements through one of four methods—a warning, a tariff reduction, a license suspension, or a license revocation. The licensee can appeal a penalty at a commission hearing.
- **Defining electricity market rules**. The PSRC is in charge of defining rules for the relationship between Licensees operating in the sector
- **Mediating disputes between licensees and customers**. Licensed operators must submit all customer complaints to PSRC. The PSRC has the authority to rule on disputes

- **Setting quality of service requirements**. The PSRC must set service quality standards for all electricity services provided to customers.

B.2 Regulatory Framework for Renewable Energy

The following regulations provide incentives for investment in renewable energy generation:

- **Electricity Purchase Agreements.** The Energy Law mandates that, during the first 15 years of operations, 100 percent of electricity produced from new renewable energy systems must be purchased at tariff levels set by the PSRC
- **Tariff Incentives**. The PSRC supports renewable energy investments through fixed-rate feed-in tariffs. As of January 2011, the feed-in tariff for electricity generated from wind was US$ 0.09/kWh, for biomass – US$ 0.10/kWh and US$ 0.05/kWh for electricity generated from small hydro-power plants.[35]

B.3 Tariff Setting Methodology

The PSRC establishes the procedures for setting and reviewing tariffs. According the Energy Law, the PSRC can either set the specific monetary value of the tariff or establish a clear formula for calculating the tariff based on parameters defined in the Energy Law.

According to the Energy Law, a tariff should cover:

- Justified operation and maintenance costs
- Loan service costs
- Costs related to environmental standards
- Mothballing and preservation costs
- Costs of the safe keeping of the utilized nuclear fuel and requisite allocations to the Nuclear Plant Decommissioning Fund
- Technical and commercial losses
- Other justified costs as provided by Legislation.

The tariff should also provide the operator with the opportunity to make a reasonable profit.

The PSRC or the Licensee can request a tariff review every six months. Once requested, a tariff review must be submitted within 90 days. The PSRC is authorized to set long-term tariffs for more than six-months if it is considered necessary to provide investment security. Once a tariff is set, licensees cannot appeal the amount of a tariff. The only recourse for altering an assigned tariff is to petition the PSRC's tariff methodology.

35 A small hydro-power plant is a hydro-powered plant with a nameplate capacity of less than 30 MW. The mentioned tariffs are VAT exclusive.

B.4 Electricity Service Quality Standards

The PSRC establishes and monitors service quality standards in the electricity sector. A 2001 amendment to the Law on Electricity Distribution Company Privatization removed a mandatory investment quota (US$ 80 million) on new electricity distribution companies (EDCs); instead, service quality standards were enacted as a method of regulating performance. In 2005, the PSRC first developed a list of standards and now licensees are monitored for compliance with these standards, which include the following:

- System average interruption frequency (interruptions/customer)
- System average interruption duration (minutes/customer)
- Average frequency of non-standard customer voltage.

Appendix C: Armenia's Energy Sector Comparisons

Table C.1: Comparing Armenia's Reforms

Reform Status	Armenia	Georgia	Azerbaijan	Macedonia	Hungary	Bulgaria
Private Sector Participation	Y	Y	N	Y	Y	Y
Regulator	Y	Y	Y	Y	Y	Y
Unbundled	Y	Y	Y	Y	Y	Y

Table C.2: Armenia's Energy Sector Compared to Other Countries against Key Indicators

	ECA Region						Non-ECA Region	
Key Indicators	**Armenia**	**Georgia**	**Azerbaijan**	**Macedonia**	**Hungary**	**Bulgaria**	**Denmark**	**Switzerland**
CO2 (tonnes) per capita (2007)	1.6	1.17	3.22	4.48	5.36	6.57	9 (2005)	6 (2005)
Energy intensity (kgoe per GDP)	0.171	0.213	0.329	0.187	0.151	0.281	0.105	0.102
Electricity consumption, kWh per capita (2006)	1585 (1692*)	1549	2514	3495	3882	4311	6864	8360
Electricity System Total Losses (2005)	17.9% (14.6% **)	43.0%	20.1%	25.0%	n.d.	14.6%	4.0%	7.0%
Electricity outages, days per year (2005)	1.36	39.01	12.97	1.85	1.57	2.83	n.d.	3.73
Residential electricity tariff, US cents/kWh (2008)	7.85	9.58	7.49	7.01	20.34	11.24	42.89	13.6
Residential gas tariff, USD/GJ (2008)	8.17	9.07	1.73	5.83	20.64	14.59	45.94	20.70
Gas consumption, m3 per capita (2008)	627.2	396.4	1225	34.35	1312	446	834.9	449.4
Total Gas Losses (2005)	7.20%	3.44%	5.10%	No data	No data	2.20%	No data	No data

Source: IEA, WDI, ERRANet, CIA World Factbook *2007 **2009

Appendix D: Armenia's Electricity Infrastructure

Armenia's electricity sector consists of five main publicly and privately owned generation companies, one publicly owned transmission company and one privately- owned distribution company. Appendix D provides an overview of the existing infrastructure and planned upgrades for each of these segments of the Armenian electricity sector.

D.1 Generation

Armenia depends primarily on three types of power generation: thermal, nuclear, and hydropower. Wind power was added to the generation mix in 2005. The installed capacity of all generation plants in Armenia is 3,147 MW. However, the installed capacity does not reflect the restricted availability of many of these plants due to their poor operating conditions or, for hydropower plants, environmental restrictions. Table D.1 lists Armenia's major power plants and information about their installed capacity, summer and winter availability, age and ownership. The sub-sections that follow provide details on the current infrastructure and planned upgrades for each type of generation.

Table D.1: Capacity, Age and Ownership of Armenia's Power Plants

Plant Name	Type	Installed Capacity	Operable capacity		Commissioning Date	Ownership
			Summer	*Winter*		
Hrazdan	Thermal	810	416.5	470	1969	Russian Federation (HrazTes ojsc)
Yerevan	Thermal (CHP)	550	59.5	50	1965	Ministry of Energy and Natural Resources, GoA
Metsamor Unit 2	Nuclear	408	358.2	388	1980	GoA (under financial management of INTER RAO-UES)
Sevan-Hrazdan Cascade	Hydro	561.4	216.7	96	1940-1962	RAO "Nordic"
Vorotan Cascade	Hydro	400	186	168	1970-1989	GoA
Small Hydro Power Plants	Hydro	76	54.6	26	N/A	Various owners
Lori 1	Wind	2.64	0.3	1	2005	GoA

D.1.1 Thermal

Armenia has two thermal power plants (TPPs) - Hrazdan TPP and Yerevan TPP - with total installed capacity of 1,756 MW. The TPPs are mainly used to cover winter peak loads, and to substitute for the Metsamor nuclear power plant during its shut-down for maintenance in late summer or early autumn.

Table D.1 shows that Armenia's TPPs have been operating for nearly 40 years; therefore, their operable capacity is well below their nameplate ratings.

New units are being installed at both thermal power plants:

- Hrazdan TPP. Armrusgazprom received a license from the Public Services Regulatory Commission (PSRC) in June 2009 to construct the fifth unit of the Hrazdan TPP, and the electricity will be transmitted to the Iranian power grid in exchange for gas from Iran. The unit will have an installed capacity of 440 MW and is expected to become online in 2011.
- Yerevan TPP. A new combined-cycle gas turbine was commissioned in 2010; it has an installed capacity of 240 MW and most of the electricity generated will be supplied to Iran in exchange for gas imports.

D.1.2 Nuclear

The Metsamor NPP, a dual reactor plant with capacity of 815 MW, is the sole nuclear power plant in the country. The plant was Armenia's largest source of generation capacity until 1988 when a major earthquake forced the plant to shut down. The Government of Armenia restarted Metsamor Unit 2 in 1995. The plant has undergone more than one hundred safety and security upgrades since its reopening.

Currently, The Government of Armenia owns the plant. Inter RAO-UES (a subsidiary of Russian companies RAO-UES and RosEnergoAtom) manages financial operations.

Armenia formally agreed in 2007 to close the Metsamor nuclear power plant. Currently, the Government plans to start the decommissioning of the plant in 2016. In December 2008, the Government of Armenia announced a tender for the right to design and oversee construction of a new nuclear plant. WorleyParsons, an Australia engineering firm, won the bid. The Government expects that the new plant will be commissioned sometime after 2017.

D.1.3 Hydroelectric

Total capacity of all hydropower systems is 1,032 MW. Plants on the Hrazdan and Vorotan rivers generate the majority of the country's hydroelectric power. The Sevan-Hrazdan cascade consists of six power plants with a total capacity of 561 MW. The Vorotan cascade consists of three power plants with a total capacity of 404 MW. The Sevan-Hrazdan system is owned by a subsidiary of RAO-UES of Russia, RAO Nordic. The Vorotan Cascade is owned by the Government of Armenia.

There are currently 102 small hydropower plants in operation, with a combined installed capacity of 132 MW. Dzoraget HPP is the largest, with 10 mini-hydro units having 26 MW of installed capacity. In 2006, the Cascade Credit, a universal credit organization, began financing of new small hydropower plants or expansion of the capacity of existing plants. The project was financed with loans from the European Bank for Reconstruction and Development (EBRD), the World Bank, and Cascade Credit's own resources.

There are also three new medium-sized hydro plants planned for Armenia:

- Meghri HPP. The Government of Armenia and the Government of Iran are partnering on the construction of two hydropower plants along the Arax River, near the border town of Meghri. Armenia's plant is expected to have an installed capacity of 140 MW. Construction is expected to commence in 2011
- Loriberd HPP. The engineering firm Fichtner completed a feasibility study of the Loriberd HPP in 2003-2004, and in 2007 updated the cost estimates. The plant will have an installed capacity of 66 MW, and a utilization factor of roughly 12 percent. Construction has not begun on this project.
- Shnokh HPP. This plant is estimated to have installed capacity of 75 MW and utilization factor is expected to be similar to Loriberd's.

D.1.4 Other Renewable

Other renewable energy generating capacity is growing in Armenia. Recent investments in non-hydro renewable energy include the following:

- **Wind**. In 2005, the Lori 1 Wind Power Plant began operation in the northern Lori region. The plant, located in Pushkin pass, includes four 690 kW wind turbines, a combined total capacity of about 2.6 MW. The Government-owned wind power plant is operated by HVEN, the state-owned electricity transmission company. Another wind field in the Karakhach region, with 90-125 MW potential, is in the planning stages.
- **Geothermal.** A 25 MW geothermal power plant is planned for Jermaghbyur (Syunik region); also, the World Bank has financed field investigations in Gegharkunik and Syunik regions to assess potential for other geothermal sites.
- **Biogas**. Gas collection wells are being installed at the Nubarashen landfill in Yerevan to collect natural gas released from solid waste breakdown. Shimizu Engineering, a Japanese firm, is installing a 1.4 MW generation unit that will use the gas to produce electricity.

D.2 Transmission

The High Voltage Electricity Network CJSC (HVEN) owns the transmission network in Armenia, [36] and is responsible for maintaining infrastructure, extending, and developing the transmission network. Armenia's high-voltage system infrastructure consists of the following:

- 164 km of 330 kV line, 1 substation
- 1,323 km of 220 kV line, 14 substations
- 3,169 km of 110 kV line, 119 substations.

Over the past ten years, HVEN has undertaken significant transmission system rehabilitation works with help from development partners. A €14.1 million loan from KfW was used to overhaul transformer stations in Kamo, Vanadzor and Alaverdi. During 1999-2004, the Electricity Transmission and Distribution Project, financed by the World Bank, provided US$ 19.75 million to rehabilitate eight transmission substations.

D.3 Power system operator and dispatch center

Power System Operator CJSC, owned by the Ministry of Energy and Natural Resources, is responsible for operation and dispatch of the high voltage network. A recently installed control and data automation system monitors grid performance and controls electricity dispatch.

D.4 Settlement center

The Ministry of Energy and Natural Resources owns the Settlement Center CJSC, founded in October 2002, and responsible for commercial settlements between power producers and purchasers.

D.5 Distribution

Electricity Networks of Armenia (ENA), a subsidiary of RAO-UES, owns and operates Armenia's distribution system. ENA owns the low-voltage distribution infrastructure and 110 kV high-voltage transmission components. The distribution system infrastructure consists of the following:

- 2,675 km of 35 kV lines, 278 substations
- 9,740 km overhead and 4,955 km cable of 6 (10) kV lines, 13,570 km overhead and 2,160 km cable of 0.4 kV lines

[36] The transmission network infrastructure includes 330 kV and 220 kV lines and substations. HVEN transferred its 100 kV lines and substations to the distribution system operator, ENA, when transmission and distribution were unbundled during sector reforms.

Upgrades to the distribution system during 1999-2010 include:

- US$ 15 million provided by USAID to improve system metering and create a Financial Settlements Center to manage the energy sector's financial flows.
- US$ 35.85 million provided by JBIC and a private investor to rehabilitate thirteen 110 kV distribution substations.
- US$ 40 million invested by ENA in 2007. Around 56 percent of the total investments were used to improve electricity service quality and 23 percent financed improvement of electricity metering and accounting.
- US$ 64.5 million corporate senior loan from the EBRD in 2009 to upgrade infrastructure and install energy meters.
- US$ 92 million to be provided by EBRD and Russia's Vneshtorgbank over the next ten years to modernize and rehabilitate the electricity grid, decrease network losses, and intensify integration with other CIS country grids

ENA plans to invest US$164 million during 2009-13 to reduce losses, improve quality of supply and energy system integration programs with other CIS countries. Table D.2 summarizes ENA's investment plans.

Table D.2: ENA's Investment Plans (2009-13)

Investment Plans (2009-13)	Estimated Cost
Civil works, procurement of required electricity transmission equipment and consulting services (construction supervision)	¥5,399 million (US$ 51.6 million)
Energy efficiency measures, including an upgrade and modernization of the low-voltage infrastructure to reduce losses and the installation of meters to improve the quality of supply	US$ 5.0 million
	€42.0 million (US$ 55 million)
	€22.5 million (US$ 30 million)
Modernization of the infrastructure	US$ 30.0 million

D.6 Regional interconnections

Armenia has installed interconnections with all neighboring countries, but so far only Georgia and Iran lines are operational. The following system components are in operation:

- 65 km of HVL-220 kV line (Armenia-Georgia)
- 35.8 km of HVL-110 kV line (Armenia-Georgia)
- 19 km of HVL-110 kV line (Armenia-Georgia)
- 78.8 km of HVL-220 kV line (Armenia-Iran)

There are two additional interconnection improvement projects in pipeline:

- A 400 kV single-circuit line with Georgia; construction to begin in 2012.
- A 300 km Armenia-Iran 400 kV double-circuit line. Construction to begin in 2011.

Appendix E: Demand Forecasting

Forecasts for electricity demand in Armenia were estimated using econometric forecasting techniques. This section provides a brief overview of how the forecasts were conducted. Section E.1 reviews the dataset used to conduct this analysis, Section E.2 describes how the forecasting model was estimated and Section E.3 describes the demand scenarios that were used.

E.1 Dataset

Quarterly electricity sales and annual tariff data were provided to us from Armenia's Public Services Regulatory Commission (PSRC). During 1999-2009 the nominal price for residential and non-residential customers remained the same. Nominal prices were converted into real terms using an inflation index (base year 1995). Figure E.1 depicts electricity sales in Armenia during 1996-2010.

Figure E.1: Total Electricity Sales (1996-2010)

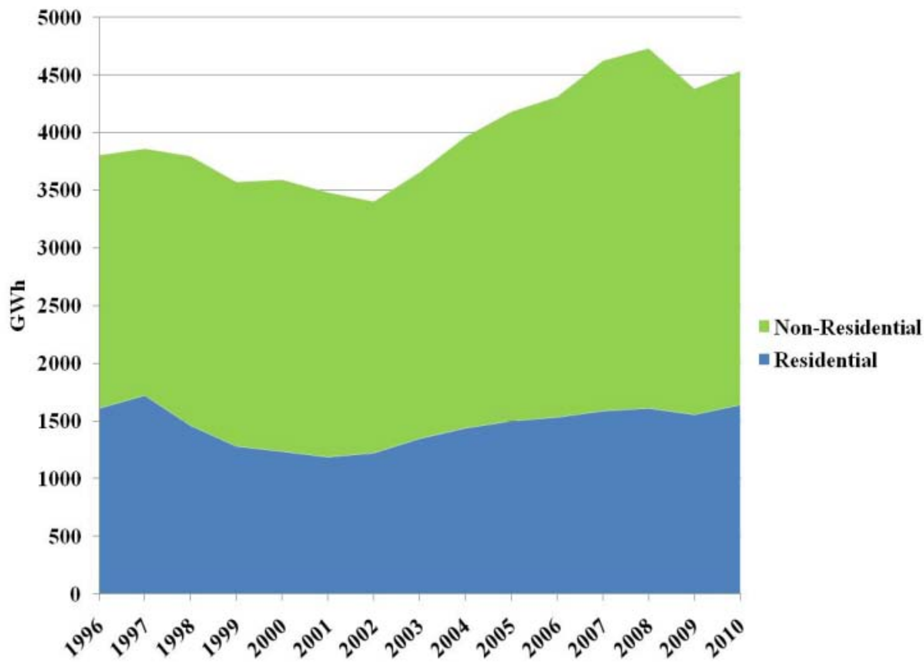
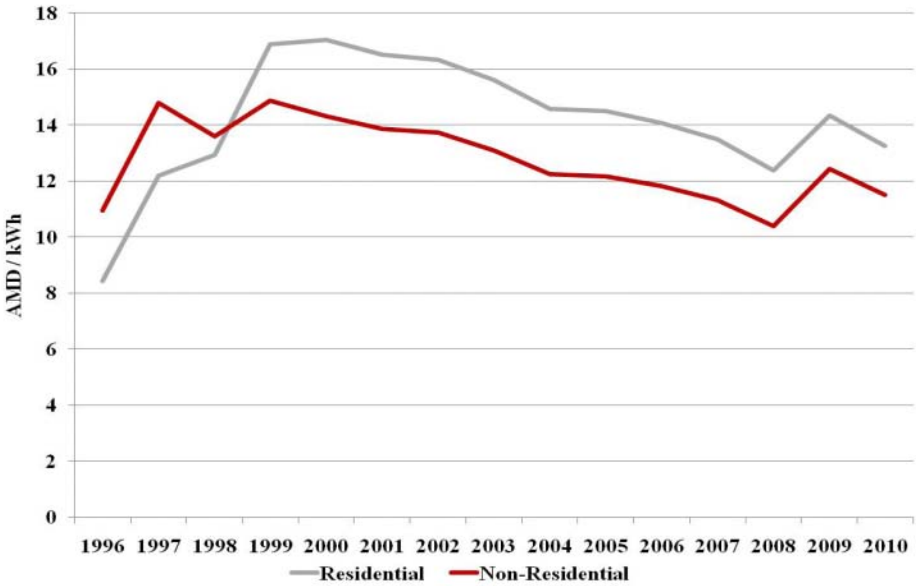


Figure E.2 depicts Real Prices from 1996 to 2010.

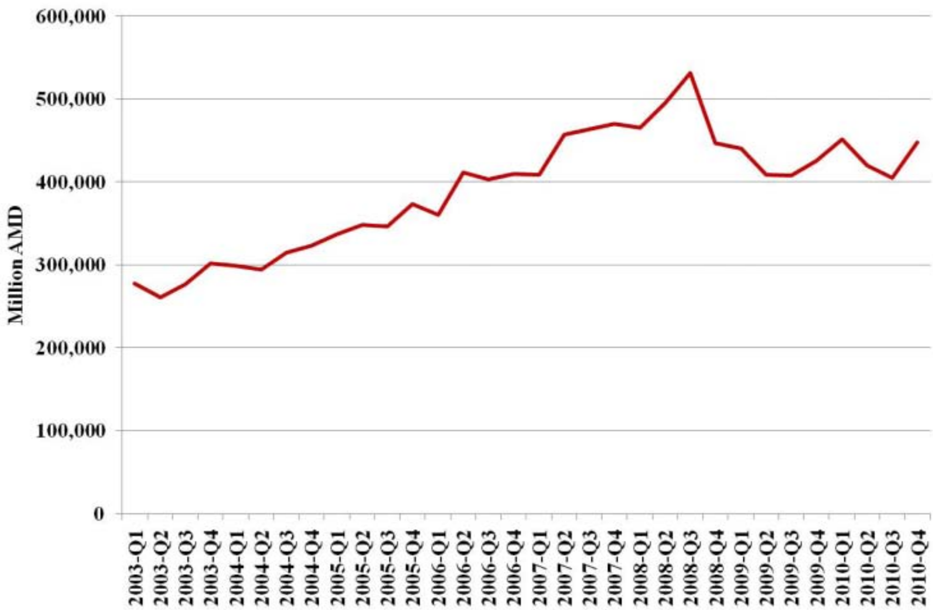
Figure E.2: Real Electricity Prices by Consumer Type



Data on nominal quarterly GDP was from the National Statistical Services of the Republic of Armenia. Due to limited data availability the time frame of evaluation was confined to 2003-10. The GDP deflator and inflation indices (for calculating price and GDP in real terms) were from the International Monetary Fund *World Economic Outlook Database*. Real GDP data was de-seasonalized using seasonal indices. The path of de-seasonalized real quarterly GDP during the evaluation period is depicted in Figure E.3.[37]

[37] The authors elected to de-seasonalize GDP to avoid multi-co-linearity issues between the independent GDP term and quarterly dummy variables. If seasonal variations had been kept in GDP, these would have correlated with the dummies for quarter 2, quarter 3, and quarter 4.

Figure E.3: Real Quarterly GDP



E.2 Forecasting Model

We follow several other studies in estimating a log-log relationship for electricity demand.[38] The benefit of using this specification is that upon estimation the coefficients represent elasticities. The general form of the model was as follows:

$$\mathbf{D} = \beta_0 \, \mathbf{Y}^{\beta_1} \, \mathbf{P}^{\beta_2}$$

D is electricity demand

β_0 is a constant

Y is GDP in year

P is price in AMD per kWh

38 Examples of studies taking this approach are the following:

Lin, Bo. "Electricity Demand in the People's Republic of China: Investment Requirement and Environmental Impact." Asian Development Bank. *Economics and Research Department Working Paper Series*. No. 37. March 2003.

Ranganathan, V. "Forecasting of Electricity Demand in Rural Area." *The Indian Journal of Statistics*. Volume 46, Series B, Part 3 (1984): 331-342.

Cebula, Richard and Nate Herder. "An Empirical Analysis of Determinants of Commercial and Industrial Electricity Consumption." *Business and Economics Journal*. Volume 2010: BEJ-7.

β_1 is income elasticity of demand

β_2 is price elasticity of demand

After logarithmic transformation, the functional form of our model was:

$$LnD = Ln\beta_0 + \beta_1 LnY + \beta_2 LnP$$

In its general form the model cannot be estimated using the ordinary least squares method because it is non-linear. Logarithmic transformation makes the model linear and allows us to conduct simple regression.

Sections E.2.1 to E.2.3 discuss how we selected the exact model specifications.

E.2.1 Model Specification

We estimated separate models for both residential and non-residential categories. The benefit of estimating two models is that we could capture how each customer group responds to changes differently. This design provided forecasts that better represent how different customers respond to changes in price and income over time.

For each model we tested different model specifications using a combination of alternative explanatory variables as well as inclusion of a lagged demand term.[39] Dummy variables for each quarter were also included in order to capture the seasonal changes in electricity demand.[40]

The preferred models were selected based on which performed best out-of-sample. Each model was fit to data for the 24 quarters from 2003 to 2008 and the results were used to forecast the known 2009 and 2010 quarterly demand levels. We evaluated models based on the Root Mean Square Error (RMSE) for the forecast years.[41] The model with the lowest RMSE was selected and then re-fit for all available quarters (2003 to 2010). Table E.1 provides an explanation for the terms used in the models described in the sections below.

[39] A lag is the use of the dependent variable from the previous period (t-1) as an independent variable. The assumption when this type of variable is included is that demand in one period is affected by the changes in the previous period. The effects from a change in one period can have a carry-over effect. Because the use of a lag model introduces the effects of another time period, these models are considered dynamic.

[40] We test dummy variables for the second, third, and fourth quarters (Q2, Q3, and Q4). Dummy variables are intercept shifters. The intercept is represented by the constant term in an econometric model. In our model the constant represents the average consumption prior to taking into consideration price or income. Including a dummy variable allows testing for systematic differences in average consumption between seasons.

[41] Root Mean Square Error (RMSE) is the square root of the average squared errors (each predicted value subtracted by the actual value, squared)

Table E.1: Explanation of terms used in econometric model

Term	Description
Y	Variable for Gross Domestic Product (GDP)
PRES	Variable for residential tariff
PNON	Variable for non-residential tariff
Q2	Dummy variable for quarter 2, takes on value of 1 if observation is quarter 2 and 0 if otherwise
Q3	Dummy variable for quarter 3, takes on value of 1 if observation is quarter 3 and 0 if otherwise
Q4	Dummy variable for quarter 4, takes on value of 1 if observation is quarter 4 and 0 if otherwise
DRES	Variable for residential electricity demand
DNON	Variable for non-residential electricity demand
Ln	Natural logarithm (logarithm to the base e), used in the equation to show that each variable takes on a logarithmic transformation
β	A beta coefficient represents the model parameter estimates obtained when conducting regression analysis
e	The disturbance or error term includes additional independent factors that are not accounted for in the model. Inclusion of a disturbance terms in the mathematical form of an econometric model is done to reflect that all models are estimates and do not represent a perfect relationship
t	The "t" subscript represents the observation time period.

E.2.2 Residential Model

Models of residential demand were tested at both the aggregate and per capita level. For each of these models we conducted specification tests on whether a lagged term should be included.

The aggregate model without a lagged demand term performed best. For this model the coefficient on price was found to be statistically insignificant. We estimated an alternative model without price and used an F-test to compare the fit of the two models. The model without price as an independent variable performed best in this test.

As a result, we selected a residential model without price as follows:

$$\text{Ln DRES}_t = \text{Ln } \beta_0 + \beta_1 \text{Ln } Y_t + \beta_2 Q2 + \beta_3 Q3 + \beta_4 Q4 + e_t$$

Overall the model explains 91.6 percent of the total variation in residential demand for the period 2003 to 2010. GDP and seasonal dummy variables were found to be statistically significant. The resulting income elasticity is 0.31. Table E.2: below shows the outcome of the estimated residential model.

Table E.2: Estimated Residential Model

Coefficients		Estimate	t Stat
β_0	Constant	**2.168**	**2.798**
β_1	GDP	**0.310**	**5.139**
β_2	Q2	**-0.433**	**-13.683**
β_3	Q3	**-0.391**	**-12.348**
β_4	Q4	**-0.102**	**-3.200**
β_0	Constant	**2.168**	**2.798**

We recognize that, given the magnitude of tariff changes expected in Armenia when the next new large generating plant is built, customers will likely change their behavior in response to changes in electricity price. In other words, , in reality, price elasticity of electricity demand would most likely be different from zero for residential customers.

We also recognize that the income elasticity of demand for electricity in Armenia (in both the residential and non-residential models) is quite low relative to other countries. Low elasticity of demand in Armenia is possibly the result of the already high levels of electrification in the country and the composition of GDP growth in the years covered by the dataset. Armenia's double-digit GDP growth from 2003-2009 was driven largely by the construction and retail sectors.

E.2.3 Non-Residential Model

Non-residential demand was estimated both with and without a lagged demand term. The aggregate model without a lagged demand term performed best. In addition we found that the dummy variables for quarter 3 and quarter 4 were not statistically significant. We conducted an F-test to compare a model with only a Q2 dummy variable to a model with all three dummy variables (Q2, Q3, and Q4). The test led us to conclude that the Q3 and Q4 variables were not worth including.[42] Based on these results the selected non-residential model was as follows:

$$\text{Ln DNON}_t = \text{Ln } \beta_0 + \beta_1 \text{Log } Y_t + \beta_2 \text{Ln PNON}_t + \beta_3 Q2 + e_t$$

Overall the model explains 91.7 percent of the total variation in non-residential electricity demand for the period 2003 to 2010. All included variables are found to be statistically significant.[43] Estimated elasticity for income is 0.38 and price is -0.38. Table B.2 below shows the outcome of the estimated non-residential model.

[42] The statistical insignificance of the Q3 and Q4 dummy variables infers that non-residential consumption patterns in quarters one, three, and four are equivalent.
[43] Coefficients on GDP, Q2, and Price were all significant at the 0.05 level.

Table E.3: Estimated Non-Residential Model

Coefficients		Estimate	t Stat
β_0	Constant	**2.617**	**2.556**
β_1	GDP	**0.379**	**7.014**
β_2	Price	**-0.375**	**-2.447**
β_3	Q2	**-0.101**	**-7.334**

Figures below show the "fit" of the model estimates compared to historical, actual consumption. Figure E.4 shows the fit of the model relative to historic quarterly data. Figure E.5 shows the fit relative to historic annual consumption.

Figure E.4: Comparison of Historic Quarterly Consumption to Model Estimates

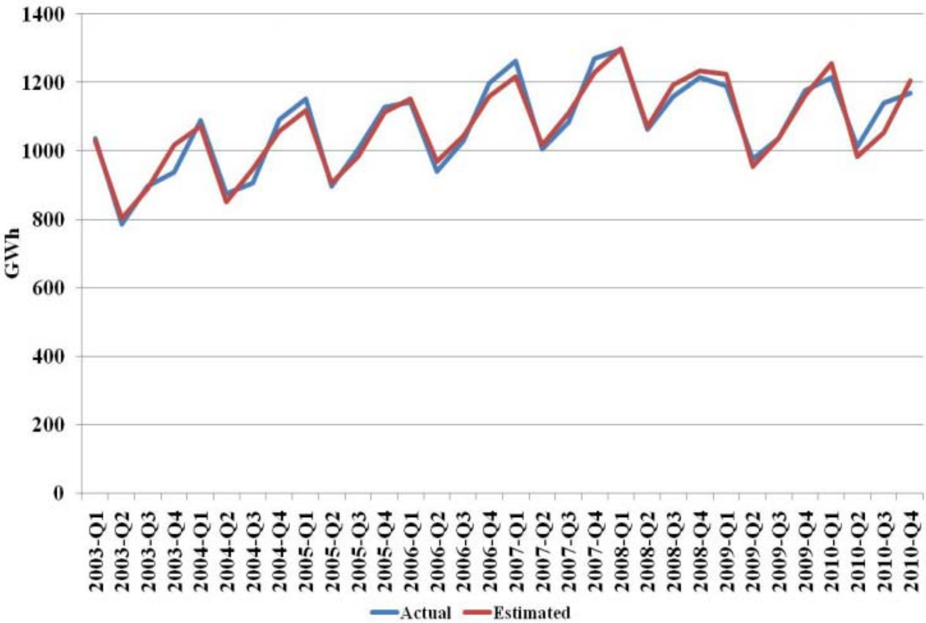
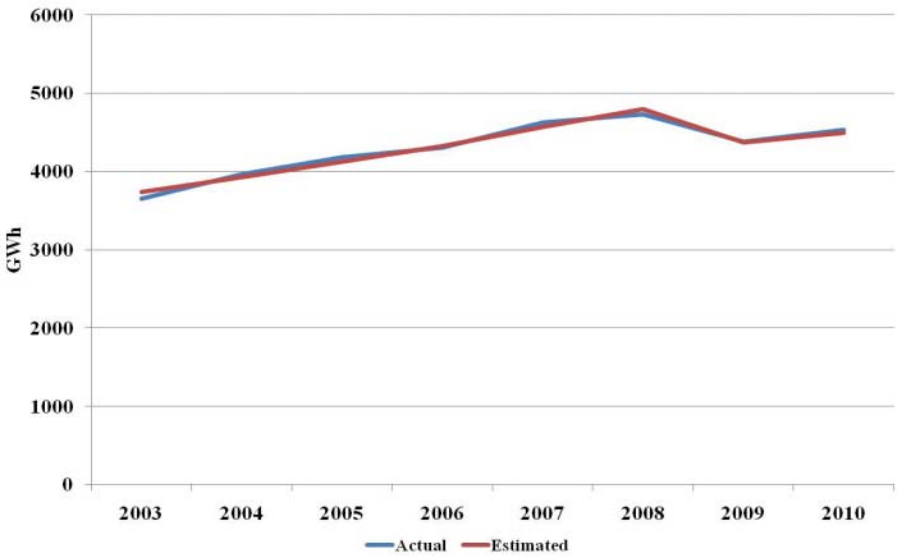


Figure E.5: Comparison of Historic Annual Consumption to Model Estimates



Demand Scenarios

The model was used to forecast demand in three cases, inputting different assumptions about GDP growth and real tariff changes:

- **Base Growth Case: Annual electricity consumption growth of 1.37 percent.** On average, GDP grows 4 percent per year in 2011 - 2030. Real electricity prices do not change. This demand scenario reflects the IMF's forecast for GDP growth in Armenia until 2016, and extends the 2016 growth rate until 2030.[44]
- **Medium Growth Case: Annual electricity consumption growth of 1.91 percent.** On average, GDP grows 5.6 percent per year in 2011 - 2030. This forecast is based on Armenia's GDP growth during 2004-2009.
- **High Growth Case: Annual electricity consumption growth of 3.74 percent.** GDP grows at roughly 11 percent per year in 2011 - 2030. This forecast is based on Armenia's GDP growth during 2003-2008, effectively treating the global recession as a macroeconomic anomaly rather than a normal part of the economic cycle.

Real electricity prices change depending on the type of new plant built and the cost of financing used (concessional or private). If no new plant is built, (as in the baseline sce-

[44] IMF World Economic Outlook 2011.

narios in Section 3.1), real electricity prices are assumed to remain constant. Appendix F describes the methodology used in modeling supply options.

Annual demand (from the econometrics forecast) was shaped to an historic (2009) hourly load curve. Thus, the load curve shape does not change between 2009 and 2029 - peak demand is assumed to grow at the same rate as electricity consumption.

Table E.4: Peak Load Forecasts 2011-2029 (MW)

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Not Ap-plicable	Not Ap-plicable	None	1253	1272	1291	1309	1327	1346	1365	1384	1403	1423	1443	1463	1484	1504	1526	1547	1569	1591	1613
Medium	Not Ap-plicable	Not Ap-plicable	None	1261	1287	1313	1338	1364	1390	1417	1444	1472	1500	1529	1559	1589	1619	1651	1682	1715	1748	1782
High	Not Ap-plicable	Not Ap-plicable	None	1287	1338	1391	1442	1496	1552	1610	1670	1732	1796	1863	1933	2005	2080	2157	2238	2321	2408	2498
Base	Comm.	250	Nuclear	1221	1234	1243	1250	1258	1266	1274	1282	1290	1298	1306	1315	1323	1332	1340	1349	1358	1366	1375

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Comm.	500	Nuclear	1221	1234	1243	1250	1258	1266	1274	1282	1290	1298	1306	1315	1323	1332	1340	1349	1358	1366	1375
Base	Conc.	250	Nuclear	1230	1247	1260	1273	1285	1298	1310	1323	1336	1349	1362	1376	1389	1403	1416	1430	1444	1458	1473
Base	Conc.	500	Nuclear	1230	1247	1260	1273	1285	1298	1310	1323	1336	1349	1362	1376	1389	1403	1416	1430	1444	1458	1473
Base	Comm.	250	Gas	1230	1248	1261	1273	1286	1299	1311	1324	1337	1351	1364	1377	1391	1405	1419	1433	1447	1461	1476
Base	Comm.	500	Gas	1221	1234	1243	1251	1259	1267	1275	1283	1291	1299	1308	1316	1324	1333	1342	1350	1359	1368	1377

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Conc.	250	Gas	1231	1250	1264	1277	1290	1303	1317	1330	1344	1358	1372	1386	1401	1415	1430	1445	1460	1475	1491
Base	Conc.	500	Gas	1222	1236	1245	1253	1261	1270	1278	1287	1296	1304	1313	1322	1331	1340	1349	1359	1368	1377	1387
Base	Comm.	250	Gas+RE+EE	1232	1250	1263	1275	1287	1300	1313	1325	1338	1351	1365	1378	1391	1405	1419	1433	1447	1461	1475
Base	Comm.	500	Gas+RE+EE	1225	1239	1249	1258	1266	1275	1284	1293	1303	1312	1321	1331	1340	1350	1359	1369	1379	1389	1399
Base	Conc.	250	Gas+RE+EE	1235	1254	1268	1282	1296	1310	1324	1338	1353	1368	1382	1397	1413	1428	1443	1459	1475	1491	1507

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Conc.	500	Gas+RE+EE	1227	1242	1253	1263	1273	1283	1293	1303	1313	1324	1334	1345	1356	1366	1377	1388	1399	1410	1422
Base	Comm.	250	Nuclear+RE+EE	1221	1232	1239	1246	1252	1259	1265	1272	1278	1285	1292	1299	1306	1313	1320	1327	1335	1342	1349
Base	Comm.	500	Nuclear+RE+EE	1221	1232	1239	1246	1252	1259	1265	1272	1278	1285	1292	1299	1306	1313	1320	1327	1335	1342	1349
Base	Conc.	250	Nuclear+RE+EE	1230	1246	1258	1269	1281	1292	1303	1315	1327	1339	1351	1363	1375	1387	1399	1412	1425	1437	1450
Base	Conc.	500	Nuclear+RE+EE	1230	1246	1258	1269	1281	1292	1303	1315	1327	1339	1351	1363	1375	1387	1399	1412	1425	1437	1450

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Medium	Comm.	250	Nuclear	1230	1250	1266	1281	1296	1311	1326	1342	1358	1374	1390	1407	1424	1440	1458	1475	1493	1510	1528
Medium	Comm.	500	Nuclear	1229	1250	1266	1281	1296	1311	1326	1342	1358	1374	1390	1407	1423	1440	1457	1475	1492	1510	1528
Medium	Conc.	250	Nuclear	1238	1263	1284	1303	1323	1343	1364	1384	1406	1427	1449	1471	1493	1516	1539	1563	1587	1611	1635
Medium	Conc.	500	Nuclear	1238	1263	1284	1303	1323	1343	1364	1384	1406	1427	1449	1471	1493	1516	1539	1563	1586	1611	1635
Medium	Comm.	250	Gas	1238	1263	1283	1302	1322	1342	1362	1383	1404	1425	1447	1468	1491	1513	1536	1559	1583	1607	1631

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Medium	Comm.	500	Gas	1229	1249	1265	1279	1294	1309	1324	1339	1355	1370	1386	1402	1419	1435	1452	1469	1486	1504	1521
Medium	Conc.	250	Gas	1239	1264	1285	1305	1326	1347	1368	1389	1411	1433	1455	1478	1501	1524	1548	1572	1597	1622	1647
Medium	Conc.	500	Gas	1230	1250	1266	1281	1296	1312	1327	1343	1359	1376	1392	1409	1425	1443	1460	1477	1495	1513	1531
Medium	Comm.	250	Gas+RE+EE	1240	1264	1284	1304	1323	1343	1363	1384	1404	1425	1447	1468	1490	1513	1536	1559	1582	1606	1630
Medium	Comm.	500	Gas+RE+EE	1233	1254	1270	1285	1301	1317	1333	1349	1366	1382	1399	1416	1434	1451	1469	1487	1506	1524	1543

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Medium	Conc.	250	Gas+RE+EE	1242	1268	1290	1310	1331	1353	1374	1397	1419	1442	1465	1488	1512	1536	1561	1586	1611	1637	1663
Medium	Conc.	500	Gas+RE+EE	1235	1257	1274	1291	1307	1324	1341	1359	1376	1394	1412	1431	1449	1468	1487	1507	1527	1546	1567
Medium	Comm.	250	Nuclear+RE+EE	1229	1248	1263	1276	1290	1303	1317	1332	1346	1360	1375	1390	1405	1420	1436	1452	1468	1484	1500
Medium	Comm.	500	Nuclear+RE+EE	1229	1248	1263	1276	1290	1303	1317	1332	1346	1360	1375	1390	1405	1420	1436	1452	1468	1484	1500

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Medium	Conc.	250	Nuclear+RE+EE	1238	1262	1281	1300	1319	1338	1357	1376	1396	1416	1437	1457	1478	1500	1521	1543	1565	1588	1611
Medium	Conc.	500	Nuclear+RE+EE	1238	1262	1281	1300	1319	1338	1357	1376	1396	1416	1437	1457	1478	1500	1521	1543	1565	1588	1611
High	Comm.	250	Nuclear	1258	1305	1347	1389	1431	1475	1521	1567	1616	1665	1717	1769	1824	1880	1938	1998	2059	2122	2188
High	Comm.	500	Nuclear	1258	1305	1347	1388	1431	1475	1520	1567	1615	1665	1716	1768	1823	1879	1936	1996	2057	2120	2186

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
High	Conc.	250	Nuclear	1266	1317	1365	1411	1459	1509	1560	1614	1669	1725	1784	1845	1908	1973	2040	2110	2182	2256	2333
High	Conc.	500	Nuclear	1266	1317	1364	1411	1459	1508	1560	1613	1668	1724	1783	1844	1906	1971	2038	2108	2179	2254	2330
High	Comm.	250	Gas	1264	1314	1361	1406	1453	1501	1551	1603	1656	1712	1769	1828	1888	1951	2016	2084	2153	2225	2299
High	Comm.	500	Gas	1255	1300	1341	1381	1421	1464	1507	1551	1597	1645	1693	1743	1795	1848	1903	1959	2017	2077	2139
High	Conc.	250	Gas	1265	1316	1363	1409	1457	1506	1557	1609	1663	1720	1778	1838	1900	1964	2030	2099	2170	2243	2319

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
High	Conc.	500	Gas	1256	1301	1343	1383	1424	1467	1510	1556	1602	1650	1699	1750	1803	1857	1912	1969	2028	2089	2151
High	Comm.	250	Gas+RE+EE	1266	1316	1361	1406	1453	1501	1550	1602	1654	1709	1765	1824	1884	1946	2010	2077	2145	2216	2289
High	Comm.	500	Gas+RE+EE	1258	1304	1345	1385	1427	1469	1513	1558	1605	1653	1703	1753	1806	1860	1916	1973	2032	2093	2156
High	Conc.	250	Gas+RE+EE	1268	1319	1366	1413	1460	1510	1561	1614	1669	1726	1784	1845	1907	1972	2039	2108	2180	2254	2330
High	Conc.	500	Gas+RE+EE	1260	1306	1349	1390	1432	1476	1521	1568	1616	1665	1716	1769	1823	1878	1936	1995	2056	2119	2184

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
High	Comm.	250	Nuclear+RE+EE	1258	1303	1344	1384	1425	1468	1511	1556	1603	1651	1700	1750	1802	1856	1911	1968	2027	2087	2150
High	Comm.	500	Nuclear+RE+EE	1258	1303	1344	1384	1425	1468	1511	1556	1603	1651	1700	1750	1802	1856	1911	1968	2027	2087	2150
High	Conc.	250	Nuclear+RE+EE	1267	1317	1363	1408	1455	1504	1554	1606	1659	1714	1772	1831	1892	1955	2020	2087	2157	2228	2303
High	Conc.	500	Nuclear+RE+EE	1267	1317	1363	1408	1455	1504	1554	1606	1659	1714	1772	1831	1892	1955	2020	2087	2157	2228	2303

* Comm.=Commercial; Conc.=Concessional

** US$/tcm.

Table E.5: Generation Forecasts 2011-2029

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Not Applicable	Not Applicable	None	4571	4639	4708	4774	4841	4908	4977	5047	5118	5190	5262	5336	5411	5487	5564	5642	5721	5802	5883
Medium	Not Applicable	Not Applicable	None	4599	4694	4788	4880	4974	5070	5168	5267	5368	5472	5577	5685	5794	5906	6020	6136	6254	6375	6498
High	Not Applicable	Not Applicable	None	4694	4882	5072	5261	5456	5660	5870	6089	6316	6551	6796	7049	7312	7585	7868	8162	8467	8783	9111
Base	Comm.	250	Nuclear	4454	4501	4532	4560	4588	4617	4646	4675	4705	4735	4765	4795	4826	4857	4888	4919	4951	4984	5016

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Comm.	500	Nuclear	4454	4501	4532	4560	4588	4617	4646	4675	4705	4735	4765	4795	4826	4857	4888	4919	4951	4983	5016
Base	Conc.	250	Nuclear	4485	4549	4597	4642	4687	4733	4779	4826	4873	4920	4968	5017	5066	5116	5166	5216	5267	5319	5371
Base	Conc.	500	Nuclear	4485	4549	4597	4642	4687	4733	4779	4826	4873	4920	4968	5017	5066	5116	5166	5216	5267	5319	5371
Base	Comm.	250	Gas	4486	4551	4599	4644	4690	4736	4783	4830	4878	4926	4974	5024	5073	5123	5174	5225	5277	5329	5382
Base	Comm.	500	Gas	4454	4502	4533	4562	4590	4619	4649	4678	4708	4738	4769	4799	4830	4862	4893	4925	4957	4990	5023

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Conc.	250	Gas	4491	4558	4608	4656	4704	4753	4802	4852	4902	4953	5005	5057	5109	5162	5216	5270	5325	5380	5436
Base	Conc.	500	Gas	4457	4507	4540	4570	4601	4631	4662	4694	4725	4757	4789	4822	4855	4888	4921	4955	4989	5023	5058
Base	Comm.	250	Gas+RE+EE	4493	4557	4605	4650	4695	4741	4787	4834	4881	4929	4977	5026	5075	5124	5174	5225	5276	5328	5380
Base	Comm.	500	Gas+RE+EE	4469	4520	4555	4587	4619	4651	4684	4717	4751	4784	4818	4853	4887	4922	4958	4993	5029	5066	5102
Base	Conc.	250	Gas+RE+EE	4503	4572	4625	4675	4726	4777	4829	4881	4934	4988	5042	5096	5152	5208	5264	5321	5379	5437	5496

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Conc.	500	Gas+RE+EE	4476	4531	4570	4606	4642	4679	4715	4753	4790	4828	4866	4905	4944	4983	5023	5063	5103	5144	5185
Base	Comm.	250	Nuclear+RE+EE	4452	4494	4520	4543	4567	4590	4614	4638	4663	4687	4712	4737	4763	4789	4815	4841	4868	4894	4922
Base	Comm.	500	Nuclear+RE+EE	4452	4494	4520	4543	4567	4590	4614	4638	4663	4687	4712	4737	4763	4789	4815	4841	4868	4894	4922
Base	Conc.	250	Nuclear+RE+EE	4485	4546	4589	4630	4671	4712	4754	4796	4839	4882	4926	4970	5014	5059	5104	5150	5196	5242	5289

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Base	Conc.	500	Nuclear+RE+EE	4485	4546	4589	4630	4671	4712	4754	4796	4839	4882	4926	4970	5014	5059	5104	5150	5196	5242	5289
Medium	Comm.	250	Nuclear	4484	4559	4616	4671	4726	4781	4838	4895	4953	5011	5071	5131	5192	5253	5316	5379	5444	5509	5575
Medium	Comm.	500	Nuclear	4484	4559	4616	4671	4726	4781	4838	4895	4952	5011	5070	5131	5191	5253	5316	5379	5443	5508	5574
Medium	Conc.	250	Nuclear	4516	4607	4681	4753	4825	4899	4973	5049	5126	5205	5284	5365	5446	5530	5614	5700	5787	5875	5965

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Medium	Conc.	500	Nuclear	4516	4607	4681	4753	4825	4899	4973	5049	5126	5204	5284	5364	5446	5529	5614	5699	5786	5874	5964
Medium	Comm.	250	Gas	4514	4605	4679	4750	4821	4894	4968	5044	5120	5197	5276	5356	5437	5519	5603	5687	5773	5861	5950
Medium	Comm.	500	Gas	4482	4555	4612	4665	4719	4773	4828	4884	4940	4998	5056	5114	5174	5234	5295	5357	5420	5484	5548
Medium	Conc.	250	Gas	4519	4612	4688	4761	4836	4911	4988	5066	5145	5225	5307	5390	5474	5559	5646	5734	5824	5915	6007
Medium	Conc.	500	Gas	4485	4560	4618	4673	4728	4785	4842	4899	4958	5017	5077	5137	5199	5261	5324	5388	5453	5519	5585

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Medium	Comm.	250	Gas+RE+EE	4521	4611	4685	4755	4826	4898	4972	5046	5122	5199	5277	5356	5436	5518	5600	5684	5770	5856	5944
Medium	Comm.	500	Gas+RE+EE	4496	4572	4632	4688	4745	4803	4862	4921	4981	5042	5103	5166	5229	5293	5358	5424	5491	5559	5627
Medium	Conc.	250	Gas+RE+EE	4531	4626	4704	4779	4856	4934	5013	5093	5175	5258	5342	5428	5515	5603	5693	5784	5877	5971	6067
Medium	Conc.	500	Gas+RE+EE	4503	4583	4647	4707	4768	4830	4892	4956	5020	5085	5152	5219	5286	5355	5425	5496	5568	5640	5714

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
Medium	Comm.	250	Nuclear+RE+EE	4482	4552	4605	4654	4704	4754	4805	4857	4909	4962	5016	5070	5125	5181	5237	5294	5352	5411	5470
Medium	Comm.	500	Nuclear+RE+EE	4482	4552	4605	4654	4704	4754	4805	4857	4909	4962	5016	5070	5125	5181	5237	5294	5352	5411	5470
Medium	Conc.	250	Nuclear+RE+EE	4516	4603	4674	4741	4809	4878	4948	5020	5092	5165	5240	5315	5392	5469	5548	5628	5709	5792	5875
Medium	Conc.	500	Nuclear+RE+EE	4516	4603	4674	4741	4809	4878	4948	5020	5092	5165	5240	5315	5392	5469	5548	5628	5709	5792	5875

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
High	Comm.	250	Nuclear	4589	4758	4913	5064	5220	5381	5546	5717	5893	6074	6261	6453	6652	6857	7068	7285	7509	7741	7979
High	Comm.	500	Nuclear	4588	4758	4912	5063	5219	5379	5544	5714	5890	6071	6257	6450	6648	6852	7062	7279	7503	7734	7971
High	Conc.	250	Nuclear***	4618	4805	4977	5147	5322	5503	5691	5885	6086	6293	6508	6730	6959	7196	7442	7695	7958	8229	8510
High	Conc.	500	Nuclear	4618	4804	4976	5145	5320	5501	5688	5882	6082	6289	6503	6724	6953	7189	7434	7687	7949	8219	8499
High	Comm.	250	Gas	4612	4794	4962	5128	5299	5475	5658	5846	6041	6242	6450	6665	6887	7117	7354	7599	7852	8114	8385

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
High	Comm.	500	Gas	4578	4742	4891	5035	5184	5338	5496	5658	5826	5998	6176	6359	6547	6741	6940	7146	7358	7576	7800
High	Conc.	250	Gas	4615	4800	4971	5139	5312	5491	5677	5869	6067	6271	6483	6702	6928	7162	7404	7654	7913	8180	8456
High	Conc.	500	Gas	4581	4746	4897	5043	5194	5349	5509	5674	5843	6018	6198	6383	6574	6771	6974	7182	7397	7619	7847
High	Comm.	250	Gas+RE+EE	4617	4798	4965	5129	5299	5474	5654	5841	6034	6233	6439	6651	6871	7098	7332	7574	7824	8083	8350
High	Comm.	500	Gas+RE+EE	4589	4755	4905	5052	5203	5359	5519	5684	5854	6029	6209	6395	6587	6784	6987	7196	7411	7633	7862

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
High	Conc.	250	Gas+RE+EE	4625	4811	4983	5152	5327	5507	5694	5887	6087	6294	6507	6728	6956	7192	7436	7689	7950	8220	8499
High	Conc.	500	Gas+RE+EE	4595	4764	4918	5069	5224	5384	5548	5718	5893	6073	6259	6450	6647	6851	7060	7276	7499	7728	7965
High	Comm.	250	Nuclear+RE+EE	4588	4753	4903	5048	5199	5353	5513	5677	5846	6020	6199	6384	6574	6769	6971	7179	7393	7613	7840
High	Comm.	500	Nuclear+RE+EE	4588	4753	4903	5048	5199	5353	5513	5677	5846	6020	6199	6383	6574	6769	6971	7179	7393	7613	7840

Demand	Financing*	Gas Price**	Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
High	Conc.	250	Nuclear+RE+EE	4620	4803	4971	5137	5308	5485	5667	5856	6051	6253	6461	6677	6899	7129	7366	7612	7865	8127	8398
High	Conc.	500	Nuclear+RE+EE	4620	4803	4971	5137	5308	5485	5667	5856	6051	6253	6461	6676	6899	7129	7366	7612	7865	8127	8398

* Comm.=Commercial; Conc.=Concessional

** US$/tcm.

*** The forecast shown is lower than that for the corresponding scenario in Figure 4.10 because it forecasts end-use energy consumption only. Figure 4.10 includes own-use by generators, system losses, and exports.

The supply model (described in Appendix F) simulates the dispatch of plants on an hourly basis, to meet hourly load for each year. Only the plants to meet demand are dispatched.

Appendix F: Supply Side Methodology

A spreadsheet model was created to achieve the following:

- Simulate the dispatch of existing and new power plants under different demand scenarios to year 2029.
- Forecast the average system tariff to year 2019.

Section F.1 explains how dispatch of power plants was simulated to meet demand. Section F.2 explains how the average system tariff was calculated.

F.1 Dispatch Simulation

The dispatch simulation adds as many MW of capacity as needed to meet peak demand under demand scenarios specified in Appendix E.

The model allows for flexibility in specifying which new plants are added, and when, and which existing plants are retired, and when. Also, the model allows for flexibility in setting the system reserve margin and plant dispatch hierarchy (the order in which plants are dispatched). All scenarios in this study assume the following:

- Nuclear and old TPPs retire in 2016
- Yerevan CCGT comes online in 2010
- Meghri HPP comes online in 2019, but capacity and energy are used for export only
- Yerevan CCGT comes online in 2010 and Hrazdan5 comes online in 2011, but 75 percent of energy and capacity are for export (25 percent of plant capacity is available for domestic energy needs).
- Reserve margins = 25 percent, unless it is assumed that a new nuclear plant comes online, in which case the reserve margin = 35 percent
- Transmission and distribution losses total 13 percent; own use by generators is roughly 5.0 percent
- Plants are dispatched according to the following hierarchy and only if they are in service:
  - Imports
  - Metsamor Nuclear Power Plant
  - Lori-1 wind power plant
  - New Wind Plant
  - Existing Small Hydro Plants
  - New Small Hydro Plants

- Shnokh HPP
- Loriberd HPP
- New Nuclear or Gas
- Sevan-Hrazdan Cascade
- Vorotan Cascade
- Dzorahek
- Hrazdan 5 (25 percent)
- Yerevan CCGT (25 percent)
- Yerevan TPP
- Hrazdan TPP
- Cogeneration

Table F.1 provides details about specific power plants, including installed capacity, operable capacity, heat rates, and asset lives.

Table F.1: Physical Assumptions about Specific Power Plants

Plant	Installed Capacity (MW)	Operable capacity (MW)	Heat Rate (btu/kWh) (if applicable)	Asset Life – new plants only (years)
Existing Generation				
Vorotan Cascade	404	404		N/A
Dzorahek HPP	26.4	14		
Sevan-Hrazdan Cascade	561.4	351.6		
Metsamor (ANPP)	408	407.5		
Small HPPs	89.4	89.4		
Yerevan TPP	550	50	10,306	
Hrazdan TPP	1,110	800	10,384	
Lori-1 WPP	2.64	2.64		
Cogeneration	0.11	0.11		
Possible New Generation				
Hrazdan 5	440	118.8	8,333	30
Yerevan CCGT	240	60	6,390	30
New Gas Plant	1,100	935	6,075	30
New Nuclear Plant	1,100	1,023	9,830	50
Meghri HPP	140	95.8		40

Shnokh HPP	70	35		40
Lori-Berd HPP	66	23.5		30
Small HPPs	200	80		40
Wind	175	52.5		40

F.2 Tariff Calculations

Tariffs were estimated or calculated for each generating plant included in the simulated dispatch. Existing plants' tariffs were assumed equal to tariffs set by the PSRC. For new plants, LEC was calculated using a discounted cash flow (DCF) model for each new plant. The levelized cost is calculated as the minimum required tariff (AMD/kWh) that would enable plant owners to cover all O&M costs, and all debt and equity costs. In other words, the levelized cost is the full cost of service.

These DCF models included assumptions about the following:

- *Plant costs.* Armenia's Least Cost Generating Plan (LCGP), internal World Bank estimates, and international industry benchmarks were used as sources for estimates of capital costs, variable O&M, fixed O&M, and decommissioning costs (for the nuclear plant).
- *Capacity:* Installed capacity and operable capacity. To estimate operable capacity, existing plants were rated downward based on their historic capacity factors, (reflecting various technical reasons that they cannot run all the time), For new plants, capacity was de-rated based on how much other new plants of the same type are able to operate.
- *Asset life* (different for each plant).
- *Loan tenures.* Twenty-year loan terms for all new plants.
- *Cost of capital* (cost of debt and equity). The cost of debt was assumed to be 10.39 percent for commercial financing and 5.05 percent for concessional financing. The cost of equity was assumed to be 18 percent. Two scenarios were simulated for the structure of financing: (i) all-debt financing ("concessional financing"); and (ii) 70/30 debt/equity mix ("commercial financing").
- *Corporate tax.* The model assumes 20 percent corporate tax in all cases.
- *Load factor.* The load factor depends on the level of plant operation required to meet forecast demand (which depends on the dispatch hierarchy). If the plant is lower in dispatch hierarchy (dispatched later, for economic reasons), and demand is low, the plant has a lower load factor.

The DCF calculations for new plants were completed only after dispatch had been simulated and a load factor estimated for each plant. A weighted average tariff was then calculated from the levelized costs of new plants and tariffs of existing plants. The weights assigned were volumes (GWh) generated in the simulated dispatch.

Table F.2 provides detail on cost assumptions for potential new power plants, including capital costs, variable O&M, and fixed O&M.

Table F.2: Cost Assumptions about Specific Power Plants

Plant	Capital Costs ($/kW)	Variable O&M ($/kWh)	Fixed O&M (S$/kW/year)
Hrazdan 5	454.5	0.87	14
Yerevan CCGT	171.9	0.96	15.04
New Gas Plant	600	0.87	14
New Nuclear Plant*	5,500	0.2	53.4
Meghri HPP	1,000		13.9
Shnokh HPP	1,818.2		10.1
Lori-Berd HPP	1,818.2		13.9
Small HPPs	1,000		12
Wind	1,500		12

*Decommissioning costs for: new nuclear plant = US$ 330.5 million; ANPP = US$ 285 million

For transmission and distribution charges, existing tariffs for ENA, HVEN, and the Settlements Center were added to the generation cost calculated above. In addition, the amortized cost of US$ 300 million of investments planned for transmission and distribution (described in section 4.2 and Appendix D) were added to the tariff.

Appendix G: Recent Experience with Construction of New Nuclear Plants

This appendix analyzes recent international experience in nuclear plant procurement and construction for the purpose of informing the Government's thinking about some of the potential challenges it may face and the cost implications of those challenges.

G.1 Introduction

Armenia has a power system able to meet peak demand in the short-term, but the planned decommissioning of the Metsamor NPP in 2016 is expected to leave a substantial gap in baseload capacity. The Government plans to fill this gap with a new, 1000-1100 MW nuclear power plant on the same site.

For the most part, nuclear technology has not changed over the past 25 years. Light water reactors dominate the scene, though heavy-water natural uranium CANDU reactors are also available. Estimating the cost of a new reactor is a daunting exercise. The database of reactors underway or completed is small, almost entirely in Asia, and mostly accumulated in the 1990s, however, there has been significant real escalation in worldwide materials costs since 2002. The supply chain - key materials, components, skilled labor - is very tight.

Total cost or life-cycle costs of a nuclear reactor can be broken down into three categories:

- Capital or construction costs
- Operating, maintenance, and fuel costs
- Decommissioning and waste removal costs

Cost figures can be reported in several formats. Capital costs are typically presented as "overnight costs" or the costs of engineering, procurement, and construction prior to taking financing and cost escalations into consideration. These figures are given in per kW or MW units by dividing by the total capacity of the plant. Total costs can also be given in levelized terms, in which costs are divided by total lifetime output of the plant in per kWh or MWh units.

G.2 Capital Costs

The main factor in the life-cycle cost of a nuclear reactor is construction or capital cost. This represents 80-90 percent of overall life-cycle cost.

For the most part one must turn to South Korea and Japan for construction costs. These are nations that maintained a nuclear building program in the 1990s, and, therefore, have experienced construction crews and other forms of indigenous infrastructure. The

US, Western European, and Russian industries have been largely moribund since the accidents at Three Mile Island and Chernobyl.

G.2.1 Experience in Japan

A 2003 MIT study provides data on experience of construction of advanced light water reactors in Japan between 1993 and 2002.[45] Table D.1 summarizes the results of this study.[46]

Table G.1: MIT Cost Estimates based on Light Water Reactors in Japan

Plant	Capacity (MW)	Date of Commercial Operation*	Overnight Cost (2007 US$/kW)
KK3	1,000	January, 1993	3,617
KK4	1,000	January, 1994	3,608
Genkai 3	1,180	February, 1994	3,656
KK6	1,356	January, 1996	3,167
KK7	1,000	January, 1997	2,707
Genkai 4	1,180	July, 1997	2,711
Onagawa 3	825	January, 2002	3,332
Y5	1,000	January, 2004	2,352
Y6	1,000	January, 2005	2,290

*Or expected at the time of the study.

G.2.2 Experience in the United States

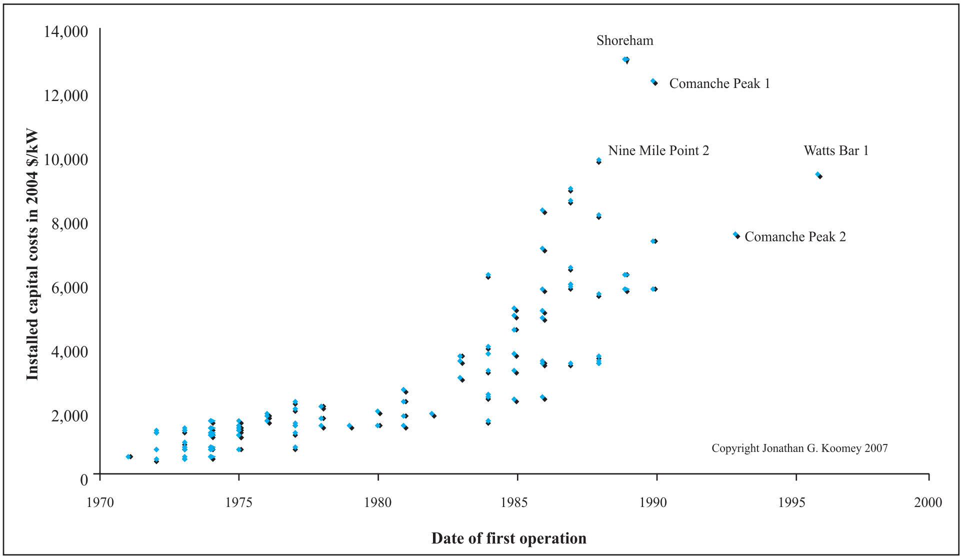
Experience in the U.S. is less recent than in Japan. Between 1970 and 2000, plant costs increased at rates far exceeding general inflation.[47]

[45] John Deutch and Ernest Moniz *et al.*, *The Future of Nuclear Power—An Interdisciplinary MIT Study*, Washington, DC: MIT, 2003.

[46] South Korean units were not used in calculating the average due to their lower labor rates.

[47] Koomey, Jonathan, and Nate Hultman. 2007. "A Reactor-Level Analysis of Busbar Costs for U.S. Nuclear Plants, 1970-2005." *Energy Policy* (accepted, conditional on revisions).

Figure G.1: Capital Costs of U.S. Reactors Built between 1970 and 2000



Source: Koomey, 2007.

During the 1970s, typical utility practice was to solicit a bid for a new nuclear steam supply system (NSSS) from a vendor (General Electric, Westinghouse, Combustion Engineering, Babcock & Wilcox, or General Atomics). Typically, the utility would hire an architect-engineer (e.g., Bechtel) to manage engineering design, procurement, and contracting. Today, the approach is different; utilities expect vendors to hire architect-engineers and manage construction. During the 1960s vendors did this, delivering a turn-key unit for a fixed price. Today's projects are turn-key in the sense that vendors manage construction and procurement but they are not turn key in terms of being built for a fixed price.

Vendors may bid project elements at a fixed price, but there is little evidence of vendors willing to bid most of the project at a fixed price. Bids typically include elements that are fixed or firm, meaning indexed to various escalators; and variable, meaning passed through at whatever the cost turns out to be. The range in cost estimates may be substantially explained by levels of escalation risk borne by the vendor. Often, vendor bids are not directly comparable; some bids may include some owners costs (e.g., cooling towers), while others do not.

Real costs escalate during this time period for many reasons:

- Volatile prices for materials that are traded primarily in international markets
- The changing exchange rate of the US dollar.
- Strong demand for construction materials, especially in China and India.

- Supply-chain imbalances and possible scarcity pricing, for suppliers, sub-suppliers, engineering-procurement-contracting (EPC) firms, and skilled labor.
- Rising contingency premiums, and/or hedging costs, throughout the supply-chain.
- Poor or unsophisticated cost estimates from 2000-2004.

There is evidence that costs have continued to escalate since 2000. Table G.2 shows recent estimates of real and nominal as well as projected escalation rates, estimated by various organizations.

Table G.2: Estimates of Capital Cost Escalation from Various Entities

Source	2004-2007 nominal	2004-2007 real	Future	Basis
The Keystone Center*	6.0 %	3.3%	0-3.3% real	Chemical plant
American Electric Power	10.5 %	7.8%	NA	Heavy construction
Cambridge Economic Research Associates (CERA)**	16 %	13.3%	NA	Utility generation
FP&L	10.7-20.7 %	8-18%	1-2% real	Construction indices

* This refers to the Keystone Center Nuclear Power Joint Factfinding Report. June 2007 (http://keystone.org/files/file/about/publications/FinalReport_NuclearFactFinding6_2007.pdf)
** CERA Power Plant Capital Cost Index (PCCI).

Table D.3 summarizes overnight cost estimates from recent studies, including some of those cited in Table G.2.

Table G.3: Comparison of Recent Overnight Cost Estimates

Source	$/kW overnight cost
Keystone (2007)	2,950
Constellation Energy (2008)	3,500-4,500
Eskom (South Africa, 2009)	6,000
FP&L (2008) filing to Alabama PSC*	3,108-3,600-4,540
Duke Energy (2008)	5,000

* Florida Power & Light, a US utility recently filed testimony before the Alabama Public Service Commission, with costs escalated from another utility's (Tennessee Valley Authority or TVA) 2005 estimate for new units in Bellefonte, Alabama. The vendor's EPC (engineering, procurement, and construction) cost estimate for Bellefonte was given as $1,611/kW in 2004 dollars, not including owners costs. FP&L escalated the vendor's estimates using a range of escalation rates and contingency assumptions, plus owner's costs. The FP&L analysis includes $200-250/kW in transmission integration costs.

G.2.3 International experience

Recently, industry and government estimates for nuclear construction around the world ranged from US$ 1,500-2,100/kW, expressed in dollar values for different years.[48] However, recent bids and industry estimates are far higher. In June 2009, the Ontario Power Authority declined to accept bids for two reactors from either AECL (US$ 10,800/kW) or Areva (US$ 7,375/kW). Areva was "non-conforming," which presumably means that substantial risk of delay and cost escalation was placed on the utility. The Electricity Supply Commission of South Africa also declined to accept bids in 2010, the lowest of which was reportedly US$ 6,000/kW.

G.2.4 Future escalation of capital costs

Long construction periods and high capital intensity are the primary reasons for escalation of nuclear power costs. Planning and construction delays can amplify nuclear plant costs due to accruing interest. The United Kingdom (UK) Department of Trade and Industry (DTI) estimates that planning can take up to eight years and construction can take 5-8 years.[49] Because nuclear plants are more capital intensive, factors that affect capital costs will be more acute than for other generating options.

The cost of delays

A 2007 study by the UK DTI compared several planning period scenarios for a nuclear plant using a gas plant as a base case. Table D.4 displays DTI analysis of the penalties and advantages of nuclear generation under various scenarios. Under the long planning period, the net present value (NPV) of the gas option is US$ 96.3 million greater than if nuclear power is installed. However, when shorter and less expensive planning stages are considered nuclear is clearly the best generation option. For the short (5.5 years) and low cost (US$ 150 million) planning period, nuclear power has a US$ 233.1 million benefit over gas generation.

[48] This covers the range estimated in studies by the University of Chicago and MIT, and the U.S. Energy Information Administration estimate for advanced US light water reactors.

[49] Department of Trade and Industry. "The Future of Nuclear Power". 2007. Interest during construction depends on several key factors including duration of construction, shape of outlays, debt-to-equity ratio, and returns on both debt and equity. The U.S. Energy Information Administration assumes a six-year construction period for a new reactor. Some vendors believe it can be done in four years.

Table G.4: Cost Advantages and Disadvantages of Nuclear versus Natural Gas

	Levelized nuclear cost US$/MWh)	Levelized gas cost (US$/MWh)	Annual cost/ benefit of nuclear (US$ million/GW)	Net present value of cost/benefit over 40 years (US$ million/GW)
8 year planning period, costs of US$ 375 million	56.55	55.95	-4.2	-96.3
5.5 year planning period, costs of US$ 250 million	55.95	55.95	0.45	12.6
5.5 year planning period, costs of US$ 150 million	54.6	55.95	10.2	233.1

The causes of delays

Factors that cause delays include:

- **Limited supplier competition and long lead times.** The worldwide forging capacity for pressure vessels, steam generators, and pressurizers is limited to two qualified companies—Japan Steel Works and Creusot Forge—and the reactor builders compete with each other and with simultaneous demand for new refinery equipment. Japan Steel Works prices have increased by 12 percent in six months, with a new 30 percent down payment requirement.[50] Other long lead-time components, including reactor cooling pumps, diesel generators, and control and instrumentation equipment have six-year manufacturing and procurement requirements
- **Foreign suppliers complying with domestic regulatory requirements.** In the near term, reliance on foreign manufacturing capacity could complicate construction and licensing. Recently, the US Nuclear Regulatory Commission (NRC Chairman Dale Klein indicated that relying on foreign suppliers requires more time for quality control inspections so substandard materials are not incorporated in U.S. plants.[51]
- **Shortages of experienced contractors.** As an example from the U.S., a study by GE-Toshiba identified a potential shortage of craft labor within a 400-mile radius of the Bellefonte site, forcing the adoption of a longer construction schedule.[52] Other sources have pointed to the potential for skilled labor shortages if nuclear construction expands.[53]

50 "Supply Chain Could Slow the Path to Construction, Officials Say," *Nucleonics Week*, February 15, 2007. Comments of Ray Ganthner, Areva.

51 *Ibid.*

52 "GE/ Toshiba, Advanced Boiling Water Reactor Cost and Schedule at TVA's Bellefonte Site," Aug. 2005, pp. 4.1-2 and 4.1-23.

53 "A Missing Generation of Nuclear Energy Workers," NPR Marketplace, April 26, 2007. "Vendors Relative Risk Rising in New Nuclear Power Markets," *Nucleonics Week*, January 18, 2007. http://

Several of these problems have surfaced at the Olkiluoto 3 site, where the French vendor Areva is building a 1,600 megawatt advanced European pressurized reactor (EPR). Areva originally estimated a four-year construction period, but the plant has fallen 18 months behind schedule, and is substantially over budget. Analysts estimate that Areva's share of the loss on the "turn-key" contract will exceed US$ 1.0 billion. Concrete poured for the foundation of the nuclear island was found to be more porous than the Finnish regulator would accept. Hot and cold legs of the reactor cooling system required re-forging. Recently, construction has been suspended, based on escalating friction between Areva and STUK, the Finnish safety regulator.

At a recent conference in Nice, France, Areva NP President Luc Oursel indicated that the company had underestimated what it would take to reactivate the global supply chain for a new nuclear plant. In particular, they were not "100 percent assured to have a good quality of supply," were not sufficiently familiar with the "specific regulatory context" in Finland, and began building without a complete design. Some 1,360 workers from 28 nations are now at work at the site. The STUK project manager added that, "a complete design would be the ideal. But I don't think there's a vendor in the world that would do it before knowing whether they would get a contract. That's real life."[54]

Recent examples of project delays

The following nuclear projects suffered delays over the past decade:

- **Olkiluoto-3 (Finland).** Anticipated completion date for the third (1,600 MW) unit of Finland's Olkiluoto NPP was 2009. Repeated delays extended this from 2011 to mid-2012 to 2013. Longer-than-expected civil works are cited as a source of delay: (i) foundation irregularities slowed many construction tasks for months until the problem was corrected; (ii) technical issues arose with the reactors unique double containment system; and (iii) the state regulator ordered welding of the cooling system to be stopped after it determined the welding of pipes was not properly. The originally expected to cost some US$4.2 billion, the price has now increased to over US$ 5.3 billion. A report analyzing the construction problems cites unrealistic budgets and time-tables as one of the leading causes.
- **Flamanville-3 (France).** The Flamanville-3 plant in France is a copy of the Olkiluoto-3 plant being constructed in Finland. This plant has also been affected by delays. Safety inspectors have found cracks in the concrete base and steel reinforcements installed in the wrong place. The project is now more than 25 percent over budget.
- **Lungman NPP (Taiwan).** Since construction at the Lungman NPP project began in 1997, the project has been delayed due to political and contractual issues.

marketplace.publicradio.org/shows/2007/04/26/PM200704265.html.

[54] Lack of Complete Design Blamed for Problems at Olkiluoto 3, *Nucleonics Week*, May 17, 2007. Areva Official Says Olkiluoto 3 Provides Lessons for Future Work, *Nucleonics Week*, May 3, 2007.

Originally planned to be completed in 2004 and 2005, the two 1,350 MW reactors are now not expected to come on-line until 2011 and 2012. Political disagreement over the project caused construction to be suspended for four months in 2000. The project was further delayed when contractors (GE) would not resume work until they were compensated for the four month construction suspension. Overall, the delay in the project caused Taiwan Power an estimated US$394 million due to contractor compensation costs and foregone revenue.

- **Belene NPP (Bulgaria).** The Belene NPP in Bulgaria has been delayed several times since it was started in 1987. Construction was originally stopped following the collapse of the Soviet Union in 1990. The project was re-started in 2002, but trouble attracting financing delayed the start of construction. Delays have resulted in estimated costs escalating from €4 billion in 2004 to €8 billion in 2008.

G.3 Operating, maintenance, and fuel costs

One of the most important parameters affecting life-cycle cost is reactor performance, or capacity factor. U.S. average nuclear capacity factors have increased from below 60% during most of the 1980s to nearly 90% in the post-2000 period.[55] Some of the increase is attributable to changes in technical specifications that require equipment to operate within a wider range and to higher fuel enrichments. The first reduces the number of equipment related reactor trips and shutdowns. The second reduces the number of refueling outages. It may also be true that outages are more frequent in early years ("teething") and later years ("aging"). Seventy five to eighty five percent is a reasonable lifetime range for future units.

Advanced light water reactors may have lower operations and maintenance costs than current units, based on the use of more passive safety systems. Including capital additions (essentially capitalized operations and maintenance), the current US average is about US$ 0.011 to US$ 0.012 per kWh in O&M costs.[56] There is no recent history of real escalation in the value, and it is probably appropriate for both a low and high estimate.

Nuclear fuel costs have many components—uranium mining and milling, conversion to UF6, enrichment, reconversion, fuel fabrication, shipping costs, interest costs on fuel in inventory, and spent fuel management and disposition.

Uranium conversion, enrichment, and fuel fabrication represent some 90 percent of total fuel costs. A January 2010 study by the World Nuclear Association estimates that total fuel costs are approximately US$ 0.071 per kWh. This estimate is based on an average burn rate of 360,000 kWh per kg of reactor grade uranium. Table D.5 below details the cost component of each step in fuel modification.

55 MIT, "The Future of Nuclear Power," 2003; and Joskow, "Future Prospects for Nuclear-A US Perspective," Presentation at University of Paris, Dauphine, May 2006.

56 Inclusive of administrative and other general operating costs

Table G.5: Cost of reactor grade uranium[57]

Step	Product	Per Unit Cost	Total Cost
Mined Uranium	8.9 kg of U_3O_8	US$ 155.50	US$ 1,028
Conversion	7.5 kg of Uranium	US $12	US$ 90
Enrichment	7.3 SWU*	US$ 164 per SWU	US$ 1,197
Fuel fabrication	1 kg of fuel pellets	US$ 240	US$ 240
Total	**1 kg of reactor grade uranium**	**US$ 2,555**	**US$ 2,555**

* A Separated Work Unit (SMU) is equivalent to one kilogram separated work. The unit defines the work needed to increase the percentage of Uranium-235.

Uranium prices have been volatile over the past three decades. Real spot prices almost sextupled from 1973 to 1976, then dropped steeply through 2002, but have risen dramatically since that time. The problem is not declining physical supplies of uranium, cost of production, or growth in demand for nuclear fuel. The key problem is that much uranium demand over the past two decades has been met by inexpensive "secondary supplies," including surplus inventories from cancelled or shut-down units (1980s-1990s) in the US, Western Europe, and Russia, purchase of surplus Russian and US government stockpiles (mid-1990s), and diluting highly enriched uranium from surplus Russian nuclear weapons (1998-2003) with natural uranium.

Worldwide uranium production is about 60 percent of current uranium demand.[58] Existing spot uranium prices clearly support enhanced production, both in the US and abroad, but lead times for new mines are long. The same situation applies to enrichment. Uranium mining expansion will need to be better than 1980s rates of expansion to meet 2015 demands, particularly with limited enrichment capacity worldwide.

Nuclear plant owners, and utility customers, are not currently facing strikingly higher fuel prices, mainly because current contracts were written during a period of surplus, and include price ceilings. The same basic situation applies to enrichment cost and supply. Most current long-term contracts expire by 2012, and secondary supplies decline rapidly during that period. The price ceilings in long-term contracts also mean that those parties that might pursue new mines or enrichment plants have not benefited substantially from price signals in the spot market. It also means that utilities with uranium and enrichment contracts largely expiring in 2012-2013 must enter the market this year to ensure adequate supplies going forward.

57 World Nuclear Association. "The Economics of Nuclear Power." April 2010. Link: http://world-nuclear.org/info/inf02.html (accessed on 30 June 2010).

58 Dr Thomas Neff, Center for International Studies, MIT, "Dynamic Relationships Between Uranium and SWU Prices: A New Equilibrium, Building the Nuclear Future: Challenges and Opportunities."

Back-end costs

Back-end costs include costs related to plant decommissioning and long-term management of spent fuel (radioactive waste). France builds decommissioning and waste disposal costs into the total cost of the plant, historically this has accounted for 10 to 15 percent of levelized costs. Other countries impose levies on nuclear facilities for eventual nuclear disposal—in the U.S. the fee is US$ 0.01 per kWh sold. Sweden has imposed a fee ranging from US$ 0.08 to US$ 0.25 per kWh that covers both waste management and decommissioning costs.[59]

A 2005 study by the OECD's Nuclear Energy Agency compares decommission estimates by plant type from 26 countries. Table D.6 displays these results.

Table G.6: Average Decommissioning Costs

Plant Type	Average Cost (US$/KW)	Standard Deviation
Pressurized Water Reactor (PWR)	320	195
Water-Water Energy Reactor (WWER)*	330	110
Boiling Water Reactor (BWR)	420	100
Pressurized Heavy Water Reactor (PHWR)	360	70
Gas-cooled Reactor (GCR)	>2,500	-

* WWER is the Russian version of a Light Water Pressurized Reactor.

[59] Clerici, Alessandro. "The Role of Nuclear Power in Europe." World Energy Council, 2007. Link: http://www.worldenergy.org/documents/wec_nuclear_full_report.pdf (accessed 7 July 2010).

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