ARMENIA NEW NUCLEAR UNIT INITIAL PLANNING STUDIES

PROGRAM TO STRENGTHEN REFORM AND ENHANCE ENERGY SECURITY IN ARMENIA

CONTRACT NUMBER EEP-I-00-03-00008-00

OCTOBER 2008

This publication was produced for review by the United States Agency for International Development. It was prepared by PA Government Services Inc.

Armenia New Nuclear Unit Initial Planning Studies

Contract No. EPP–I–00–03–00008–00
Task Order No. 800

Program to Strengthen Reforms and Enhance Energy Security in Armenia

October 2008

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Version: 1.0

Initial Planning Studies

Executive Summary

October 2008

EXECUTIVE SUMMARY

The 2006 Least Cost Generation Plan (LCGP) was prepared by the Ministry of Energy of the Republic of Armenia (RoA) with support from PA Consulting Group (USAID's "Program to Strengthen Reform and Enhance Energy Security in Armenia"). The LCGP concluded that Armenia will need to construct substantial new electrical generation capacity by the time the existing Armenian Nuclear Power Plant (ANPP) is shut down for decommissioning and that a new nuclear power plant would enhance Armenia's energy security at the least-cost.

The primary objective of New Nuclear Unit Initial Planning Study (IPS) is to support the MoENR and other RoA organizations in implementing an integrated approach to evaluating a nuclear power plant project. The IPS covers 15 topics, which are discussed in the individual sections of the report. The topics of the IPS address all of the program planning and policy issue topics identified in the nuclear power program planning guidelines of the International Atomic Energy Agency (IAEA).

The baseline assumptions for the IPS are that a new nuclear unit would be constructed on the ANPP site and would begin operation in January of 2017, at which time the existing ANPP will be shutdown for decommissioning. The results of the IPS provide the technical information, alternatives, conclusions, and specific recommendations necessary for the RoA to develop the policy decisions and action plans to proceed with the new NPP project.

Section 1 of the IPS, Survey of the International Supply Situation for Nuclear Power Plants, identifies and evaluates the potential suppliers of nuclear power plant (NPP) systems suitable for Armenia based on technical, economic, schedule, and project risk aspects. An initial screening evaluation of all existing NPP designs was performed using the criteria that the capacity should not be more than 1200 MWe and that the design should be already operating or under construction. The screening identified three NPP designs suitable for Armenia. The Westinghouse AP1000 is an "Advanced Passive" pressurized water reactor (PWR) with a net generation capacity 1,117 MWe. The Evolutionary CANDU 6 (EC 6) is designed by Atomic Energy of Canada Limited (AECL). The EC 6 is a Pressurized Heavy Water Reactor (PHWR) that has a net generation capacity of 670 MWe. The current version of the VVER-1000 PWR design offered by ATOMSTROYEXPORT (ASE) is the AES-92, with a net generation capacity of about 1000 MWe.

A survey of these candidate designs was performed through a survey questionnaire provided to the vendors and review of public information. Based on the results of the survey, each of the three candidate NPP designs would be suitable for Armenia. Each design has completed a safety review by the nuclear regulator in its country of origin. They each have a similar seismic design basis, which will need to be modified to the seismic hazard of the ANPP site. The estimated capital and operating costs on a per MW basis are all within the range of uncertainty of the estimates. The estimated construction schedules are the same.

In estimating the construction costs for the candidate designs, the following adjustments were made to vendor provided construction cost estimates to account for Armenia specific conditions:

- Single unit factor (13%)

- Escalation to 2007 dollars

- Seismic hazard at ANPP site (> .3 g) will require seismic isolators or other modification to the standard design

- Natural Draft Cooling Tower

- Upgrade/refurbishment of ANPP pumping station and piping

- Owner scope (15%)

- Operating and maintenance costs were adjusted for local wage rates

After adjustments, candidate designs are similar in construction cost, approximately $3,000/kw in 2007 dollars, without escalation, contingency, interest during construction (IDC), or value added tax (VAT).

The EC 6 design has a number of unique features that are would be beneficial in the situation of Armenia, which are summarized as follows:

- Smaller size. The smaller generation capacity of the EC 6 is a much better match to Armenia's electric demand than either of the other candidate designs.

- Load following capability. The EC 6 has the most rapid load following capability, which is an important characteristic for the Armenian system with its large variations in daily load.

- Fuel diversity: The use of natural uranium or alternative fuels widens the source of supply and results in a lower fuel cost. If significant uranium deposits are found in Armenia, fuel could be manufactured locally, enhancing energy security. There is also the potential to use recovered uranium from the spent fuel of the ANPP for the EC 6.

- No reactor vessel. This allows on-power refueling, resulting in potentially higher capacity factors and eliminates the need for a large reactor vessel, which will be difficult to transport into Armenia. The heaviest component in the EC 6 design is considerably smaller than for the PWR designs.

The EC 6 is a widely used design for which a supply chain has already been established. This is a substantial advantage in reducing the risk of construction delays due to problems with equipment suppliers, such as those currently being experienced by the Olkiluoto NPP project in Finland.

There are two disadvantages to the EC 6 design. Following a plant trip, there is a delay of about 36 hours before the plant can be restarted. This situation will not be experienced very often because the EC 6 design can accept a 100% load reduction without trip. The other disadvantage is the need for a one year outage to replace the pressure tubes of the reactor after about 30 years of operation.

The primary advantage of the AP 1000 design is the relative simplicity of the safety systems. Besides significant improvement in the level of safety, this simplicity will provide operational and economic benefits because there are fewer pumps, valves, controls, and other components than a conventional PWR. These reductions in equipment and bulk quantities lead to major savings in plant costs and construction schedules. The primary disadvantage of the AP1000 is its relative large capacity, which may not be usable at times with Armenia's load profile. The large and heavy components of the AP1000 will also be a challenge to transport into Armenia by road.

The principal advantage of the AES 92 design is the existing relationship with ASE, which should contribute to the availability of support services, and technology transfer provisions. Also developing the regulatory program for the new plant should be much simpler. One disadvantage of the AES 92 is that has a lower seismic design basis, which will require more enhancements to meet Armenia conditions.

In addition to these standard designs, Armenia should consider a hybrid design using technologies from different vendors to meet unique requirements or to obtain most favorable commercial terms. For example, the Temelin NPP in Czech Republic has a VVER 1000 reactor; control system and nuclear fuel from Westinghouse, and turbine generator provided by Škoda Pilsen.

IPS Section 2, Review of Nuclear Fuel Supply Options, examines capability of major fuel suppliers to provide fuel for alternative NPP designs. This study concludes that there would be multiple nuclear fuel suppliers for each candidate design. This should ensure availability of fuel supply at competitive prices. Despite recent spikes in uranium prices, nuclear fuel prices are not expected to escalate substantially in the future. The Global Nuclear Energy Partnership (GNEP) Reliable Fuel Services initiative will provide additional assurance of source of supply for nuclear fuel that is not subject to political disruption. The fabrication of EC 6 natural uranium fuel in Armenia, similar to the programs in Romania, Argentina, and Korea is feasible, although the cost may be somewhat higher than purchase of fuel from established suppliers.

IPS Section 3, Review of Regional Export Possibilities and Grid Requirements, examines the potential for export of excess electricity from the new nuclear unit to neighboring countries. The study concludes that the export of excess capacity from the new nuclear unit to neighbor countries is technically and economically feasible as well as necessary to achieve the design capacity factor needed for cost effective operation. Annual system load duration curves for the Armenia system in 2017 and beyond were developed based on the growth forecasts of the LCGP and system operating data over the past two years. From analysis of the load duration curves, it is concluded that, from plant startup in 2017 until well beyond 2030, a 1000 MWe plant would operate at far less than the expected 90% capacity factor if only Armenia domestic load is served. This is because there are large seasonal and daily variations in the domestic load and rules for dispatch restrict load on largest generator to 75% system load. The new unit capacity available for export: would 1,750 GWh in 2017, 650 GWh in 2030.

The study also examined regional markets for electricity. The electrical demand in Iran has been growing faster than its generating capacity. Unlike Armenia, Iran's summer peak load is approximately 50% higher than the winter peak, creating the opportunity to export during periods of relatively low domestic consumption in Armenia. The existing agreement with Iran for exchange of 3 kWh of electricity for 1 cubic meter of gas provides a market for electricity export from the new nuclear unit. Based on forecast gas prices, the value of the gas received should be well above the production cost of the new nuclear unit. Growth in electricity demand in Azerbaijan, Turkey, and Georgia as well as the forecast increase in natural gas prices should make electricity from the new nuclear unit competitive in these countries. An agreement for sale of electricity by Armenia to Eastern Turkey was recently announced. However, because the seasonal demand profile in these countries is similar to Armenia, there would be less capacity available for export.

In addition to existing connections, Armenia is constructing 400 kV lines from Hrazdan to Iran and Georgia. Interconnection to the planned 500kv line in Georgia will allow export to Turkey and Azerbaijan. Exporting the power from the new nuclear unit to Georgia and Iran will require completion of a 400 kV line from the ANPP site to the Hrazdan substation, estimated cost of about $40 million.

IPS Section 4, Assessment of the National Infrastructure Requirements, evaluates the infrastructure requirements, capabilities, constraints, development needs, and costs. Specific topics covered are grid stability, cooling water, transportation of heavy loads, industrial support, and feasibility of construction of the new ANPP unit. Concerning grid stability, load flow calculations indicate that, with recently completed and planned upgrades to the transmission system, the Armenia grid could accept a large NPP without adverse impact on stability. However, the construction of a 400 kV line to connect the new NPP to Hrazdan 5 substation is necessary for export of electricity.

The new unit will require more than twice the flow of cooling water as the existing ANPP. It was concluded that there is sufficient water in the Sevjur River and collection pond to provide water for new NPP in the same way as is done for the ANPP, although some small reduction for other users may be needed. The approximately 6 % reduction in water available to agriculture and fisheries users of the Sevjur could be compensated from other sources in the region or by more efficient water use practices. An alternative is to use a hybrid wet/dry cooling system, similar to that designed for the North Anna NPP, although the system has significant cost and efficiency penalties. It is recommended that MoENR should apply as soon as possible to the Water Resource Management Agency in order to have the water permits for the new NPP in place when the bid specifications are issued.

The new nuclear unit will require transporting equipment up to 8.5 meters in diameter and 650 tons. Because on the tunnels and bridges on alternate routes, road transport from the port of Batumi in Georgia is currently the only feasible option for transporting large and heavy equipment. Engineering surveys of the roadway from Batumi to Metzamor and port facilities at Batumi are needed to determine the improvements that will be needed. Armenia should establish agreements with the Government of Georgia for use of the roadway including provisions for road improvements and repairs as well as road closures during shipments.

NPP construction requires large amounts of construction materials and equipment. There is local capability to provide concrete, rebar, cable, and some electrical equipment. However, the capacity of these facilities relative to other demands during the NPP construction period must be determined. With some investment, local manufactures could begin to produce some industrial products such as cable tray, HVAC components, metal structures and office buildings, and galvanized steel. Other construction materials (e.g., pipe) and equipment will have to be imported.

IPS Section 5, Review of Options for Waste Management and Disposal of Spent Nuclear Fuel, examines the alternatives for disposal of radioactive wastes from the new nuclear unit. For low level waste, near surface disposal in a vault constructed at the ANNP site is the recommended alternative. This should be the same disposal facility constructed for disposal of the decommissioning waste from the existing ANPP. For spent nuclear fuel, several programs currently underway to develop international or regional disposal facilities should provide a means for disposal in the future. Spent fuel may to be stored in an interim spent fuel storage installation (ISFSI), similar to the one at the existing ANPP, for as long as 60 years until an international repository becomes available. RoA must establish policy, safety regulations, and funding regulations for high level and low level radioactive waste disposal.

IPS Section 6, Tariff Analyses and Financial Plan Including a Survey of Potential Financing Sources, surveyed the considerations involved in obtaining financing for the new nuclear unit; identified alternatives for financing the project; and calculated the tariff under various ownership structures. A survey was performed of potential funding sources including export credit agencies (e.g., US Export-Import Bank), international financial organizations, and banks with experience in energy projects in developing countries. The survey results indicate:

- Armenia capacity for additional debt is very limited
- Export credit agencies (ECA) of the supplier's nations are the only feasible source of debt financing
- GoA and/or investors will have to provide up to 25% of project finance

Three scenarios for NPP ownership were defined:

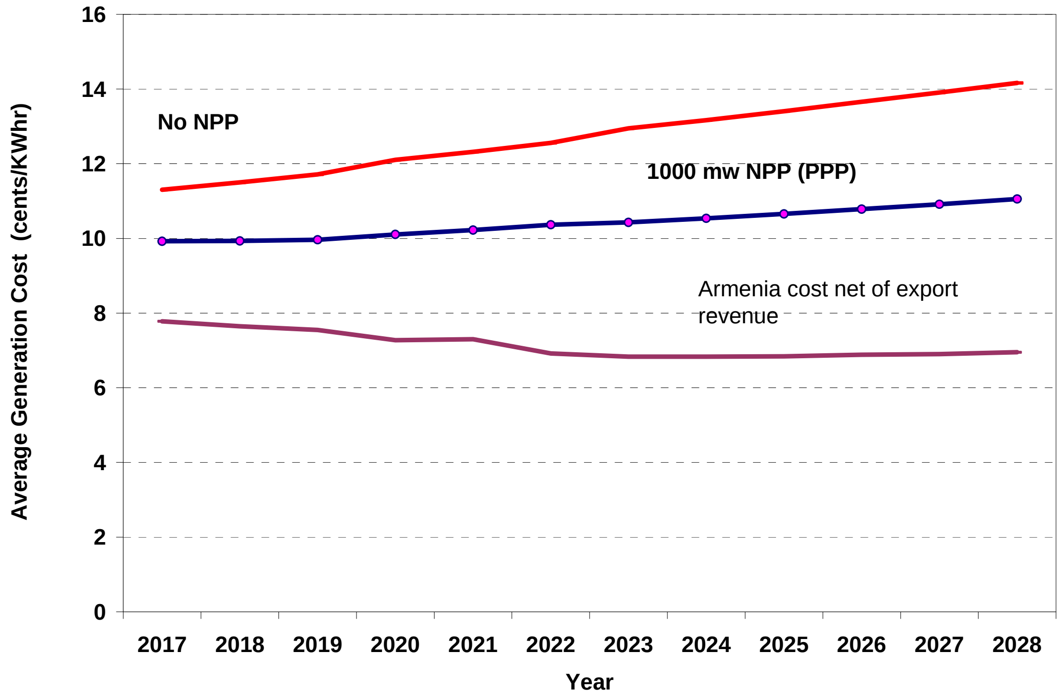
- Government Owned (GoA): This scenario has the lowest cost of capital (10%) but may not be achievable with the limited debt capacity of Armenia
- Independent Power Producer (IPP): This scenario requires little GoA funding, but has the highest cost of capital (14.7%).
- Public Private Partnership (PPP): This scenario would require some GoA funding and has a lower cost of capital (12.4%) relative to IPP

The total capital required for a 1,000 MWe nuclear unit includes the overnight cost ($3 billion) plus contingency ($450 million) and interest during construction (IDC). IDC will depend on the cost of capital and will range between approximately $1.8 billion for the GoA scenario and $3.0 billion for the IPP scenario.

To estimate the wholesale tariff for the new NPP, a financial model of the cash flows for the project from start of construction through plant shutdown after 60 years of operation was developed. The financial model calculates the tariff for the sale of electricity that would be necessary to cover all cash flows including loan principal and interest payments and dividends on the equity financing. For the GoA scenario, the wholesale tariff for the new NPP would be about 7.5 cents per kWh. For the PPP scenario, the tariff would be 9.7 cents and for the IPP case, the tariff would be about 12.7 cents. The payment of interest and principal on the capital is by far the largest component of the wholesale tariff.

An analysis of the total cost for generation in the Armenian system was performed using the system planning models developed for the LCGP, updated to include: NPP capital and operating cost parameters; current estimates for combined cycle plant capital and operating costs; and current natural gas price forecasts. The gas price forecast is based on the assumption that the price of gas in Armenia will rise to at least 80 percent of the European price by 2015 and that gas prices will continue to escalate at 2.37 percent per year. The average system generation costs calculated from the system planning model for the years 2017 through 2028 are shown in figure ES-1. The case of no NPP assumes that two 500 MWe combined cycle plants are built instead of the new NPP. The NPP case assumes the NPP is owned under the public private partnership. It can be seen, that for the case of no NPP, the tariff will continue to escalate with the price of fuel. For the NPP case, the tariff remains fairly stable. The lower curve on the graph represents the effects of export of excess capacity of the new NPP. If the gas received from the swap of the excess NPP capacity is used to fuel the thermal power plants in the system, the effect would be to lower the average generating cost of the system significantly.

Figure ES-1: Average System Generation Cost Trend



IPS Section 7, Review of Nuclear Safety Policies and Regulatory Capability, refers to a study being performed by the Nuclear and Radiation Safety Center, and USNRC. Two draft documents have been prepared and are under review by ANRA. Licensing and safety oversight of the new nuclear unit will require development of new regulations as well as significant expansion of the ANRA staffing. The "Action Plan for Updating the Regulatory Program for Oversight of Nuclear Power Reactors" provides recommendations for development of nuclear legislation, regulations, and guidance documents that are needed to license and oversee a new reactor. The recommendations include the need for ANRA to develop regulations for site requirements for seismic and other hazards and off site dose limits for accident conditions. The second document, "Staffing, Training and Technical Support for Upgrading of a Nuclear Safety Regulatory Program in Armenia" provides plans for staffing of regulatory body for new plant licensing and construction and operations. It also presents plans for training of the regulatory staff.

IPS Section 8, Assessment of the Need for International Agreements and Contracts Related to the New NPP Project, concludes that Armenia is already participating in most international conventions related to nuclear energy. However, Armenia should adopt the IAEA Convention on Supplementary Compensation for Nuclear Damage (CSC) of 1997 in order to have full access to international nuclear commerce. Armenia has been invited to join the GNEP, a voluntary international partnership of nations with interest in nuclear power, and participation in GNEP would provide significant benefits to Armenia's nuclear program. Armenia already has a Bilateral Nuclear Co-operation agreement with the Government of Russia. It is recommended that Bilateral Nuclear Co-operation agreements should be signed with the governments of candidate suppliers to have full access to the information needed to make informed decisions on supply agreements. Additionally, Armenia will need to establish agreements with Georgia for transportation of equipment. When the arrangements for disposal of spent nuclear are established, additional agreements and licenses for shipment of spent fuel through a neighbor state will need to be established.

IPS Section 9, Evaluation of the Present Engineering and Industrial Capacity in Armenia and Assessment of Nuclear Manpower Training Needs, refers to a study being performed by staff of MoENR with support from IAEA, scheduled for completion in October. This study will identify the tasks and competencies needed for each phase of the NPP project: Initial Planning, Preparation, Construction, Commissioning and Operation. It will survey the human resources in existing engineering organizations in Armenia (e.g., ANPP, CJSC Atomservice, and CJSC Armatom). It will also survey technical training institutions in Armenia and provide recommendations for human resource development and training.

IPS Section10, Review of Legal and Legislative Requirements for a New Nuclear Plant, compares the existing Armenia laws and decrees to the normal legal hierarchy applicable in most states with nuclear programs. With the new law on use of nuclear energy, Armenia has most of the legal hierarchy commonly in force for nuclear nations. It is recommended to develop legislation to implement the indemnity and insurance provisions of the CSC convention. For the case of IPP or PPP, legislation is needed to identify responsibilities and funding mechanisms for management of spent fuel and other radioactive wastes resulting from NPP operation and decommissioning. New legislation is also needed to define enforcement policy and civil penalties for violation of nuclear safety regulations. Legislation or regulation on reporting of defects and noncompliance is also recommended.

IPS Section 11, Analyses of Social and Economic Aspects of Anticipated Tariffs, reviews measures to mitigate the effects of increased electricity tariff on the poor. The retail tariff with the new NPP will be significantly higher than the current tariff but less than the tariff with gas fired generation. The RoA has an existing Poverty Family Benefit System to support low income families, which will need to be reevaluated as electricity prices increase. For the period 2017 – 2021, the additional subsidy to low income families to compensate for electric tariff increase would be about $37 million for the case of a PPP owned NPP and at least $10 million higher for the case of no nuclear.

IPS Section 12, Milestone Schedule of Activities for the Nuclear Power Plant Project, describes the scope, duration and precedence of the major activities (Level 1) of the new NPP project. It provides a Microsoft Project schedule of activities to start up the plant by December 2017. This schedule is very ambitious but achievable if started by the end of 2008. Major activities in the next 2 years are:

- Establish Managing Organization
- Complete the EIA process
- Develop Regulatory Structure
- Secure financing
- Conduct international tender
- Order Long Lead Materials (for AES 92 and AP1000, major components such as reactor vessel and coolant pumps must be ordered at least 2 years before the start of construction.

IPS Section 13, Plan for Dissemination of Public Information & Encouraging Public Participation in the Decision Process, provides a Public Consultation and Disclosure Plan and describes processes and methods to ensure availability of information as well as accurate public understanding of NPP issues. The objectives are:

- To raise public awareness of the benefits of nuclear power for Armenia and gain public support for the project;
- Ensure neighboring countries are informed about the project in an appropriate and timely manner
- Assure the international community and investors that the implementation of the project will be planned and carried out in a transparent manner and in recognition of requirements of financing institutions and nuclear regulatory agencies

The plan recommends establishing an Expert Group with experts from organizations and agencies primarily concerned by the project. Public consultation and disclosure should begin as soon as decision on new NPP is confirmed and continue until beginning of construction.

IPS Section 14, Evaluation of the Need for an Owner's Consultant, defines the roles, responsibilities, and necessary capabilities of a project Managing Organization and identifies the need for consulting support to this organization. As soon as possible, the GoA should establish a Managing Organization for NPP project preparation. Major tasks of the Managing Organization will include:

- Prepare Bid Specifications & conduct tender
- Initiate infrastructure projects
- Obtain licenses and permits including environmental assessment
- Initiate owner's scope activities
- Public information

During the planning phase, the Managing Organization will need approximately 50 full time equivalent staff with a wide range of expertise. Managing Organization will transition to oversight of the construction and operating organizations during subsequent stages of the project. Consultant tasks will depend on skills available locally but typically include:

- Project controls, planning and scheduling
- Project finance
- Records management
- Tenders and contracts
- Vendor technical review
- Infrastructure design
- Preparing applications for licenses and permits
- Oversight of the Engineering and Construction vendors

IPS Section 15: Plan for Preparing and Conducting an International Tender for the New NPP, provides a plan based on IAEA guidelines and experience of recent international tenders. The plan provides description of activities for the tender process and discusses the responsibilities for tender activities. The plan also presents the recommended content and format of the tender documents.

Initial Planning Studies

Acronyms

October 2008

1 SURVEY OF THE INTERNATIONAL SUPPLY SITUATION FOR NUCLEAR UNITS WITH COST ESTIMATES

NPP	Nuclear Power Plant
CANDU	Canadian Deuterium Uranium Reactor
ACR	Advanced Candu Reactor
SEU	Slightly Enriched Uranium
PHWR	Pressurized Heavy Water Reactor
EPR	European Pressurized Water
MHI	Mitsubishi Heavy Industries
APWR	Advanced PWR
KHNP	Korea Hydro & Nuclear Power
ASE	Atomstroyexport
GAN	Russian Regulatory Authority
WENRA	Western European Nuclear Regulators Association
EUR	European Utilities Requirements
PBMR	Pebble Bed Modular Reactor
PWR	Pressurized Water Reactor
IRIS	International Reactor Innovative & Secure
GE	General Electric
ABWR	Advanced Boiling Water Reactor
ESBWR	Economic Simplified Boiling Water Reactor
PPE	Plant Parameter Envelope
O&M	Operation & Management
EPC	Engineering Procurement Construction
FP&L	Florida Power and Light Company
TVA	Tennessee Valley Authority
SCE&G	South Carolina Electric & Gas

DOE	Department of Energy
CED	Contract Effective Date
EPC	Engineering, Procurement and Construction
CNSC	Canadian Nuclear Safety Commission
NCA	Nuclear Cooperation Agreement
IAEA	International Atomic Energy Agency
NU	Natural Uranium
SEU	Slightly Enriched Uranium
SSE	Safe Shutdown Earthquake
LOSP	Loss of Offsite Power
SG	Steam Generator
RPV	Reactor Pressure Vessel
BOO	Build Own Operate

2 REVIEW OF NUCLEAR FUEL SUPPLY OPTIONS

NPP	Nuclear Power Plant
CANDU	Canadian Deuterium Uranium reactor
GNEP	Global Nuclear Energy Partnership
IAEA	International Atomic Energy Agency
ANPP	Armenian Nuclear Power Plant
FCN	Nuclear fuel factory
ZPI	Zincates Precision Industries

3 REVIEW OF THE REGIONAL EXPORT POSSIBILITIES AND GRID REQUIREMENTS

LCGP	Least Cost Generation Plan
ANPP	Armenian Nuclear Power Plant
PSRC	Public Services Regulatory Commission
EPSO	Electric Power System Operator

UCTE	European Union for Coordination of Transmission of Electricity
RoA	Republic of Armenia
A	Ampere
TSP	Dynamic Regimes Program
PS	Power System
SP	Software Package
SC	Short Circuit
FAO	Frequent Automated Off-loading
IPF	Flow Distribution Program
MVA	MegaVolt Ampere
MVAr	MegaVolt Ampere - reactive
TPP	Thermal Power Plant
OL	Overhead (power transmission) Line
4	**ASSESSMENT OF THE NATIONAL INFRASTRUCTURE REQUIREMENTS VIS-À-VIS AVAILABLE INFRASTRUCTURE**
NPP	Nuclear Power Plant
ANPP	Armenian Nuclear Power Plant
AGC	Automatic Generator capacity Control
UES	Unified Energy Systems
SCADA	Supervisory Control and Data Acquisition System
VHL	Very Heavy Lift
l/sec	liters per second
HVAC	Heating, Ventilating and Air Conditioning
DWS	Demineralized Water System
5	**REVIEW OF OPTIONS FOR WASTE MANAGEMENT AND DISPOSAL OF SPENT NUCLEAR FUEL**
LLW	Low Level Wastes
HLW	High Level Waste

NPP	Nuclear Power Plant
PPE	Plant Parameter Envelope
WANO	World Association of Nuclear Operators
ILW	Intermediate Level waste
ANPP	Armenian Nuclear Power Plant
SAPIERR	Support Action: Pilot Initiative for European Regional Repositories
IAEA	International Atomic Energy Agency
US NRC	United States Nuclear Regulatory Commission
ISFSI	Independent Spent Fuel Storage Installation
GNEP	Global Nuclear Energy Partnership
GNPI	Global Nuclear Power Infrastructure
IUECs	International Uranium-Enrichment Centers
ARIUS	Association for Regional and International Underground Storage
KgHM	Kilogram Heavy Metal
NPT	Non-Proliferation Treaty
NTI	Nuclear Threat Imitative
6	**TARIFF ANALYSIS AND FINANCIAL PLAN, INCLUDING A SURVEY OF POTENTIAL FINANCING SOURCES**
AECL	Atomic Energy of Canada Limited
ADB	Asian Development Bank
AIG	American International Group, Inc.
AP	Final Commitment Application
ATRADIUS	Export Credit Insurance of the Netherlands
CESCE	Spanish Export Credit Insurance Company
COFACE	Compagnie Francaise d. Assurance pour le Commerce Exterieur
EBRD	European Bank for Reconstruction and Development

ECA	Export Credit Agency
EDC	Export Development Canada
ECGD	Export Credit Guarantee Department (U.K.)
EKN	Swedish Export Credit Guarantee Board
ENA	Electric Network of Armenia
EPC	Engineering, Procurement, & Construction
EULER HERMES	Export Credit Insurance of Germany
Euratom	European Atomic Energy Community
Ex-Im Bank	Export-Import Bank of the United States
G2G	Government-to-Government
GenCos	Electricity Generating Companies
GoA	Government of Armenia
HSBC	Hongkong and Shanghai Banking Corporation
IAEA	International Atomic Energy Agency
IPP	Independent Power Producer
IMF	International Monetary Fund
JV	Joint Venture
LIBOR	London Interbank Offered Rate
NEXI	Nippon Export and Investment Insurance (Japan)
NPP	Nuclear Power Plant
O&M	Operation & Maintenance
PC	Preliminary Commitment
PPP	Public Private Partnership

PRG	Partial Risk Guarantee
PSRC	Public Services Regulatory Commission
SACE	Export Credit Agency of Italy
SPV	Special Purpose Vehicle
7	**REVIEW OF ARMENIA'S NUCLEAR SAFETY POLICIES AND REGULATORY CAPABILITY**
ANRA	Armenian Nuclear Regulatory Authority
US NRC	United States Nuclear Regulatory Commission
ANPP	Armenian Nuclear Power Plant
IAEA	International Atomic Energy Agency
EIA	Environmental Impact Assessment
SAR	Safety Analysis Report
8	**INTERNATIONAL AGREEMENTS AND CONTRACTS**
NPP	Nuclear Power Plant
EBID	Environmental Background Information Document
IAEA	International Atomic Energy Agency
NPT	Non-Proliferation Trust
NSG	Nuclear Supplies Group
CSC	Convention on Supplementary Compensation
GoA	Government of Armenia
9	**ASSESSMENT OF HUMAN RESOURCE DEVELOPMENT NEEDS**
NPP	Nuclear Power Plant
ANPP	Armenian Nuclear Power Plant
MoENR	Ministry of Energy and Natural Resources
IAEA	International Atomic Energy Agency
10	**REVIEW OF LEGAL AND LEGISLATIVE REQUIREMENTS FOR A NEW NUCLEAR PLANT**

NPP	Nuclear Power Plant
IAEA	International Atomic Energy Agency
GoA	Government of Armenia
NRC	Nuclear Regulatory Commission
11	**ANALYSIS OF SOCIAL ASPECTS OF ANTICIPATED TARIFFS**
GoA	Government of Armenia
FBS	Family Benefit System
OFPL	Overall Family Poverty Level
FBALSP	Allocation and Payment Procedures For Family Benefits And Lamp Sum Benefits
WART	Weighted Average Retail Tariff
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IAEA	International Atomic Energy Agency
GoA	Government of Armenia
EIA	Environmental Impact Assessment
NSSS	Nuclear Steam Supply System
BOP	Balance of Plant
13	**PUBLIC CONSULTATION AND DISCLOSURE PLAN FOR THE NEW NUCLEAR POWER UNIT PROJECT IN ARMENIA**
GoA	Government of Armenia
IAEA	International Atomic Energy Agency
PCDP	Public Consultation and Disclosure Plan
RoA	Republic of Armenia
EIA	Environmental Impact Assessment
EBRD	European Bank for Reconstruction and Development
ANPP	Armenian Nuclear Power Plant
PSRC	Public Services Regulatory Commission

14	**EVALUATION OF THE NEED FOR AN OWNER'S CONSULTANT**
NPP	Nuclear Power Plant
TVO	Teollisuuden Voima Oyj's
STUK	Finnish Radiation and Nuclear Safety Authority
GoA	Government of Armenia
QA	Quality Assurance
15	**INTERNATIONAL TENDER PLAN**
BIS	Bid Invitation Specification
EOI	Expression of Interest
SCRNS	State Committee for Regulation of Nuclear Safety
NPP	Nuclear Power Plant
IAEA	International Atomic Energy Agency
O&M	Operation & Maintenance
RFI	Requests for Information

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The objective of this study is to identify and evaluate the potential suppliers of nuclear power plant (NPP) systems suitable for Armenia based on technical, economic, schedule, and project risk aspects.

1.1 IDENTIFICATION OF CANDIDATE NPP SUPPLIERS

There are a number of NPP designs currently offered from suppliers around the world. These offerings range from existing plants for which there is operating experience to preliminary designs which will not be ready for construction for many years. The NPP designs that are offered for export are summarized below by country of origin.

Canada

The CANDU 6 is designed by Atomic Energy of Canada Limited (AECL). CANDU stands for "CANada Deuterium Uranium". CANDU is a Pressurized Heavy Water Reactor (PHWR) that uses heavy water (deuterium oxide) for moderator and coolant, and natural uranium for fuel. The current CANDU 6 design is designated the Evolutionary CANDU 6 (EC 6) and has a net generation capacity of 670 MWe. Ten CANDU 6 reactors are currently in operation in Canada, Korea, Argentina, China, and Romania. The CANDU 6 design has been licensed by the Canadian regulatory authority as well as the regulators in the other countries where they are operating.

The Advanced CANDU Reactor (ACR) is an evolution of the CANDU 6 design with generation capacity of 1125 MWe. The ACR1000 is a pressurized heavy water reactor that uses slightly enriched uranium (SEU) fuel, light water coolant, and smaller amounts of cool, low pressure heavy water as a moderator. A safety certification of the ACR-1000 design by Canadian Nuclear Safety Commission is currently underway. ACR 1000 units are expected to be operating in Canada by 2015 and have been proposed for construction in several other countries.

Europe

Areva NP has developed a large European pressurized water reactor (EPR), which was confirmed in mid 1995 as the new standard design for France and received French design approval in 2004. It is derived from the French N4 and German Konvoi types. It has four separate, redundant safety systems rather than passive safety. EPR has a net generation capacity of 1,500 – 1,700 MWe. The first EPR unit is being built at Olkiluoto in Finland, the second at Flamanville in France. An application for design certification of a US version, the Evolutionary PWR (EPR), has been submitted to the US NRC, with approval expected by 2011. There are six EPR units planned for construction in the US.

Japan

Mitsubishi Heavy Industries (MHI) offers the Advanced PWR (APWR) with net generation capacity of 1538 MWe. The APWR is an evolution of the PWR design built by MHI in Japan. The first two APWRs are planned for Tsuruga, with construction to begin in 2010 and operation to begin in 2016. MHI is now marketing a 1700 MWe version of the APWR in the USA and Europe. The application for design certification was submitted to the US NRC in January 2008 with approval expected in 2011. The first US APWR units may be built at Comanche Peak near Dallas, Texas. In March 2008 MHI submitted the same design for EUR certification, as EU-APWR.

The ATEMA joint venture has been established by MHI and AREVA NP to develop a 1,100 MWe (net) three-loop PWR with extended fuel cycles, 37% thermal efficiency and the capacity to use mixed-oxide fuel only. They expect to have this ready for license application by 2010. The reactor is regarded as mid-sized relative to other units and will be marketed primarily to countries embarking upon new nuclear power programs.

Korea

Korea Hydro & Nuclear Power (KHNP) will be offering the APR-1400 reactor for export. Korea Power Engineering Company is the main designer, and Doosan the main manufacturer. The APR-1400 is the latest evolution of the Korean design, which was developed from the Combustion Engineering System 80+, which has a US NRC design certification. Design certification by the Korean Institute of Nuclear Safety was awarded in May 2003. The APR-1400 offers enhanced safety with seismic design to withstand 0.3g ground acceleration, and has a 60-year design life. The first APR-1400 units in Korea will be Shin Kori 3 & 4, which were licensed for construction in 2008 and will be in operation in 2013 and 2014.

Russia

The Russian Joint Stock Company, ATOMSTROYEXPORT (ASE), is responsible for the export activities of the Russian nuclear industry. ASE is offering several variations of the VVER 1000 nuclear plants. The VVER 1000 model V-428 is known as AES-91 nuclear plant and has 1000 MWe net generating capacity. The AES-91 differs from earlier VVER 1000 designs in that it uses a digital controls system designed by Siemens. The AES-91 also has extra seismic protection. Two units of this design are operating in China and one is under construction in Iran.

A more recent version of VVER-1000 is the AES-92 NPP. The AES-92 has net generation capacity of about 1000 MWe. In addition to digital controls, the AES-92 has a number of active safety systems similar to those found on a traditional Western PWRs. The AES-92 is designed for an 18 month refueling cycle and 60 year design life. Two AES-92 units are being constructed in India and two units have been licensed by the Russian Regulatory Authority (GAN) for construction as Novovoronezh 6 and 7 in Russia. The AES-92 claims to meet the European Utilities´ Requirements for safety and reliability. A variation of the AES-92 has been selected for construction in Bulgaria. According to the Bulgarian Nuclear Regulatory Authority, the NPP Belene will be licensed according to the new Western European Nuclear Regulators' Association (WENRA) reference safety levels for existing plants, which are still in discussion by WENRA.

The design of the AES-2006 NPP is currently in development and will have a net generation capacity of about 1200 MWe. AES-2006 is an evolutionary development of the AES-92 plant, with longer life, greater power and efficiency. The lead units will be built at Novovoronezh II, to start construction by 2013 followed by Leningrad II in 2013-14. They will have enhanced safety including that related to earthquakes and aircraft impact with some passive safety features. Although the design has not been certified or licensed, the AES-2006 design is intended to conform to both Russian standards and European Utilities Requirements (EUR). The EUR document is a nuclear power plant specification written by a group of potential investors in electricity generation in Europe, mostly utilities and other industrial institutions. Its membership includes organizations from EU Member States, Switzerland as well as from Russia (Rosenergoatom). The EUR document has also been used as a base for the bid specification of the new Olkiluoto 3 nuclear unit construction in Finland. It is, however, not a regulatory type of design safety standard on an EU-wide level.

Afrikantov Experimental Machine Building Design Bureau (OKBM) VBER-300 PWR is a 295-325 MWe unit developed from naval power plants and was originally envisaged to be operated in pairs as a floating nuclear power plant. It is designed for 60 year life and 90% capacity factor. It now planned to develop the VBER-300 as a land-based unit with Kazatomprom, with a view to exports, and the first unit will be built in Kazakhstan. The design has not yet been certified or licensed.

South Africa

South Africa's Pebble Bed Modular Reactor (PBMR) is being developed by a consortium led by the utility Eskom. Production units will be 165 MWe and can be constructed in groups to produce the desired capacity. PBMR has a direct-cycle gas turbine generator and thermal efficiency about 42%. A demonstration PBMR plant and fuel fabrication facility is due to be built in South Africa beginning in 2010, with fuel loading expected in 2014. The demonstration plant project has yet to begin detailed design and license applications have not been approved by South African regulators. In the US, the PBMR design is being evaluated for a nuclear-powered hydrogen production plant at the Idaho National Laboratory.

United States

The Westinghouse AP1000 is a pressurized water reactor (PWR) with a net generation capacity 1,117 MWe. AP is sometimes taken to mean “Advanced Passive”. The principal difference of the AP1000 as compared to older PWR designs is that the plant safety systems are passive, relying on naturally occurring phenomena such as gravity, natural circulation and condensation, to assure cooling of the core in the event of an accident. The additional benefit of passive design is that passive safety systems are significantly simpler than the traditional PWR safety systems. Westinghouse has commitments to design and construct four AP1000 units in China and four more in the US. Orders for another four units in the US are expected by the end of 2008. The AP1000 is also being considered in the UK, Canada, and South Africa. The Westinghouse AP1000 standard plant design received US NRC design certification in 2004. A revised version of the design certification is currently under review in the US.

Westinghouse is also leading an international consortium developing an advanced third Generation NPP called International Reactor Innovative & Secure (IRIS). IRIS is a modular 335 MWe pressurized water reactor with integral steam generators and primary coolant system all within the pressure vessel. The design is scheduled for completion by 2017.

General Electric Company's (GE) 1350 MWe Advanced Boiling Water Reactor (ABWR) nuclear plant was developed in cooperation with the Tokyo Electric Power Company and GE's partners Hitachi and Toshiba. Four ABWR units are in operation in Japan, the first started operation in 1996. Another two ABWR units are nearing completion at Lungmen in Taiwan, and one more (Shimane Nuclear Power Plant 3) recently commenced construction in Japan. Two ABWR units have been ordered for the South Texas site in the US. The ABWR received US NRC standard design certification in May 1997. ABWR has also received licensing approval in Japan and Taiwan. The ABWR is currently being reviewed by the European Utility Organization against European regulatory requirements.

GE also offers the Economic Simplified Boiling Water Reactor (ESBWR) design with a net generation capacity of 1,500 MWe. The ESBWR is a passive safety design. Like the AP1000, ESBWR safety systems are "passive" systems that utilize natural forces, including natural circulation and gravity to assure cooling of the core in the event of an accident. The ESBWR is planned for at least five new units in the US. The ESBWR has been submitted to NRC for design approval, which is expected by the end of 2009. Construction of one or more of the US ESBWRs could start as early as 2010 with commercial operation to begin as early as 2014.

Mixed Technology Plant Designs

In addition to the standard NPP designs discussed above, there have been several examples of NPPs designed to use major systems from different suppliers. For example, the Temelin NPP in Czech Republic has a VVER 1000 reactor with a digital control system and nuclear fuel designed by Westinghouse and a turbine generator provided by Škoda Pilsen. The 1,000 MW turbine, supplied by the Škoda Energo Company, ranks among the biggest machines operating at a speed of 3,000 rpm.

Similarly, the AP1000 units being constructed in China will have turbine generators designed by MHI and manufactured under license in China. The turbine generator for the standard AP1000 design is manufactured by Toshiba.

1.2 SCREENING OF CANDIDATE NPP DESIGNS

The objective of the screening evaluation of NPP designs is to identify those suitable for Armenia for detailed survey. The criteria for the screening evaluation are the generation capacity and design maturity. Because of the relatively small electrical grid in Armenia, the new nuclear unit should not have a net generation capacity of more than 1200 MWe. This capacity is about three times higher than the existing ANPP and is considered the maximum that could be run efficiently in the Armenia electrical system.

The second screening criterion is the current state of completion of the NPP design. The new nuclear unit should be completed by the end of 2016 in order to replace the existing ANPP at the end of its design life. Given the importance of the NPP project to the country and challenges of financing the project, it is considered essential that the new nuclear unit be a complete design that is already operating or under construction elsewhere.

The conformance of the candidate NPP designs to the screening criteria is represented in the Screening Matrix shown in table 1-1. The screening shows that only the EC-6, AP1000 and the AES-91 & 92 meet the criteria for both generation capacity and design completeness. These designs were selected for detailed survey as discussed in section 1.3.

It should be noted that there is significant potential for export of electric power from Armenia to heighboring countries, as discussed in IPS section 3. This export potential might justify a higher capacity plant than would be suitable for the Aremenian system by itself. In this case, an ABWR, an EPR, or a two unit EC-6 could be considered as candidates. However, the larger plants have other factors which influence their suitability for Armenia, including total construction cost and size of components for shipment into the country.

Table 1-1, NPP Screening Matrix

	Design Completeness			
Net Electric Generating Capacity (MWe)	**Currently Operational**	**Under Construction 2008**	**Under Construction by 2015**	**Available After 2015**
<400			VBER 300, PBMR	IRIS 335
400 - 800	EC-6			
800-1200		AES-91, AES-92, AP1000	ACR1000	ATMEA
>1200	ABWR	EPR APR-1400	ESBWR, APWR, AES 2006	

1.3 SURVEY OF CANDIDATE SUPPLIERS

To survey the candidate suppliers, a questionnaire was prepared. The questionnaire addressed technical, logistical, and cost issues related to the candidate design. The questionnaire was provided to Westinghouse, AECL, and ASE. In addition to the questionnaire, the AECL and ASE were asked to provide the technical information described in the NEI Plant Parameter Envelope (PPE) [(1)] for the EC-6 and AES 92. (The Westinghouse AP1000 information is already in the NEI PPE).

The responses to the survey are presented in Appendix A. Westinghouse responded to the questionnaire in an interview. AECL provided detailed technical literature which provided answers to most of the questions. AES provided some technical information but declined to provide financial information in response to the questionnaire. The results of the survey are summarized in Table 1.2.

Table 1-2, Summary of Candidate NPP Designs

	NPP Design		
Parameter	**CANDU EC 6**	**AP-1000**	**VVER AES 92**
Reactor Type	PHWR	PWR (Passive Safety)	PWR
Net Generation Capacity (MWe)	670	1,117	1,000
Design Life (years)	40, extended to 60	60	60
Design Availability	90 %	93.4%	89%
Load Follow	100%-60% in minutes	100%-50% in 2 hours	100%-50% in hours
Grid Transients	Can accept 100% loss of load without trip	Can accept 100% loss of load without trip	Unknown
Regulatory approval of design	Canada CNSC, Korea, China, Argentina, Romania	US NRC, reviews by CNSC and UK pending	Russian GAN, China, India, Bulgaria (future)
Operating Experience	11 units operating, over 100 years of operation	None, first units under construction	First AES 92 units under construction, 2 AES 91 units operating for 1 year
Weight of heaviest shipped component	Moisture Separator Reheater @ 350 ton	Steam Generator@ 650 ton	Reactor Vessel @ 450 ton
Fuel manufacturers	8 companies in 7 countries	5 companies in 4 countries	2 companies
Take back spent fuel	Not currently possible	Not currently possible	Possible
Seismic design criteria	0.3 g	0.3 g	0.24g

1.4 NEW UNIT COST ESTIMATES

The cost of electricity generation from an NPP depends on a number of factors. The factor with the largest impact on generation cost is the cost of capital. The next largest contributor to overall cost is the NPP construction cost and schedule. Repaying construction cost and interest generally accounts for about two thirds of the cost of power from a nuclear plant. The construction schedule is an important component for overall cost because interest charges on borrowed money that accumulate during the construction period represent a substantial portion of the total cost of construction. After startup, the NPP operating performance is another important factor. Because a large portion of NPP costs are fixed, regardless of plant output, the NPP's capacity factor determines the overall cost per megawatt hour (MWh). Operations and maintenance (O&M) and fuel costs are smaller but significant contributors to total generation cost. Decommissioning and waste disposal cost are not major costs if they are accurately forecasted, collected, and invested safely over the life of the plant.

The estimates of cost of capital for the new Armenia unit are discussed in IPS section 6. The following sections discuss estimates for the other factors of NPP generation costs. It should be noted that none of the cost estimates discussed in this section include Armenian Value Added Tax, import fees, or other taxes. The effects of taxes on the new nuclear project will be considered in section 6.

Construction Cost and Schedule

New power plant cost estimates are often referred to as overnight costs. Overnight cost literally represents the cost to complete a construction project overnight. It usually includes engineering-procurement-construction (EPC) costs and owner's costs, but does not include any financing costs and does not account for inflation or escalation during the construction period.

There is considerable uncertainty about the construction cost for the AP1000 plant. Credible estimates of overnight NPP construction costs in the US range from $2,400/kWe to as much as $5,000/kWe. This wide variation in costs can be attributed to several factors:

- uncertainty about escalation of commodity prices and wages,
- difficulty in producing a precise cost estimate before detailed design work is complete, and
- differences in the scope of work and contingencies included in the cost estimates

Recent cost estimates for AP1000 projects planned in the US have been provided in filings with state Public Service Commissions (PSCs) [2]. Examples include:

- In February 2008, Florida Power and Light Company (FP&L) provided its PSC with estimates for two new nuclear units at its Turkey Point site. Their estimate for overnight capital costs was between $3,108/kWe and $4,540/kWe (2007 dollars), depending on the cost of materials escalation, owner's scope and cost, and transmission integration required. FP&L based its estimate on an earlier study done by the Tennessee Valley Authority (TVA) for its Bellefonte site, adjusted for site-specific factors and elements not included in the TVA study.
- In March 2008 Progress Energy Florida presented the Florida PSC with an overnight cost estimate of $4,260/kWe (2007 dollars) for its proposed Levy two-unit NPP at a green field site.
- Based on analyses of the May 2008 South Carolina Electric & Gas (SCE&G) PSC application for building two AP1000 units at the V.C. Summer Station, their cost estimate, including escalation is $4,988/kWe (year spent dollars).

These utility estimates are considerably higher than the estimate of $2,475/kWe (2006 dollars) assumed by the US Department of Energy (DOE) in the 2008 Energy Outlook[3]. The utility estimates include significant costs for scope related to site specific factors such as cooling towers, security systems, and transmission upgrades that are not included in the DOE estimate. Utility estimates are in 2007 dollars which are at least 15% higher than DOE's 2006 estimate. Also, the utility estimates generally include larger contingency costs than the DOE estimate.

The FPL estimate[4] for constructing two new units at the site of the existing Turkey Point plant in South Florida is one of the most detailed and comprehensive estimates currently available. The FPL reference case (Case A) estimate is $3,596/kWe (2007 dollars) for the total cost of the two unit project. This estimate agrees fairly well with the estimate provided by Westinghouse of $3,500/kWe (2007 dollars) for a two unit AP1000 site in the US. For this reason, the FPL estimate was selected as the reference for cost estimate of an AP1000 plant built in Armenia

The FPL estimate identifies a number of costs elements which would be much different in Armenia. These items, with estimated change in the cost per kilowatt capacity are shown in table 1.3. Based on the adjustments described in the table, the estimated cost of a two unit AP1000 construction in Armenia would be $2,941/kWe. Note that there is no adjustment for site preparation and existing infrastructure. Discussions with managers at the existing ANPP site indicate that any existing infrastructure is not suitable for operation with the new unit and that existing administrative buildings will be utilized by the ANPP decommissioning project. Although the construction site was cleared and prepared for the construction of ANPP units 3 and 4 in the 1980's, savings in site preparation are expected to be offset by the need to demolish the many abandoned buildings in the area of the construction site.

An additional adjustment is needed to account for the fact that only a single unit will be built in Armenia. If two NPP units are built at the same site at the same time, experience suggests that both units can be built for about 12 percent less than if they were built separately(5). The savings are due to ability to schedule work crews and construction equipment more expeditiously, with less downtime, as well as economies in procurement and related support costs. Based on this adjustment, the reference cost per kWe estimate for a single unit AP1000 in Armenia would be $3,342/kWe (2007 dollars), or $3.73 billion for a plant with 1,117 MWe capacity.

The construction schedule for the AP1000 is estimated by Westinghouse as 6 years, using modular construction techniques. The difficulty of transporting large plant components into Armenia via road way may extend this schedule by as much as a year.

Table 1-3, Adjustments to Obtain Cost Estimate for AP1000 in Armenia

Cost Element	FPL Estimate ($/kWe)	Adjustment for Armenia NPP ($/kWe)	Basis for Adjustment
Additional Required Scope	36	-36	No additional scope identified. This appears to be a contingency cost.
Permit & Licensing	38	-24	Licensing and permitting in Armenia is not as elaborate as in the US
Security Infrastructure	40	-24	Security requirements in Armenia are not as elaborate as the US
Site Security	33	-22	Security requirements in Armenia are not as elaborate as the US
Transmission Integration	215	-215	Transmission Integration costs will handled separately
Allowance for Cost Risk	442	-442	Contingency costs for the project will be handled separately
Seismic Isolators	0	+90	Standard plant design is based on 0.3g safe shutdown earthquake. The higher seismic hazard at ANPP site will require seismic isolators or other modification to the standard design, estimated at $100 M per unit.
Upgrade of pumping station and piping	0	+18	Refurbish/replace pumping station and pipe that bring makeup cooling water to the plant. Estimated at $20 M per unit.
Total Adjustments		-655	

Cost estimates for the CANDU EC 6 are based on the actual costs for recently completed projects. Wolsong Units 2, 3 and 4 are CANDU 6 units in Korea, which were completed in 1997, 1998 and 1999 respectively. Quinshan II and III were completed in 2003 for a total cost of $2,060 M or $1,634/KWe. Cernavoda Unit 2 was completed in 2007. The experience of these projects has provided AECL with extensive cost data on which to estimate construction cost of new plants.

A recent AECL cost estimate for a two unit EC 6 plant in Eastern Europe was $2,317/kWe (2007 dollars). Adjusted for a single unit, the cost would be $2,632/kWe. However, this estimate did not include cost elements needed for an EC 6 plant in Armenia. The costs to be added to the AECL estimate are as follows:

- Cooling Tower: The AECL estimate is based on once through cooling. A natural draft cooling tower for the plant is estimated to cost $56 million.
- Upgrade of pumping station and piping: The pumping station and 7.5 km pipe lines that bring makeup cooling water from the Sevjur River and reservoir to the plant will need to be replaced at an estimated cost of $20 million.

- Seismic upgrade: Standard plant design is based on 0.3g safe shutdown earthquake. The higher seismic hazard at ANPP site will require seismic isolators or other modification to the standard design, estimated at $100 million.

Based on these adjustments, the estimated total construction cost would be $1.94 billion (2007 dollars) for a plant with 670 MWe net generation capacity ($2,985/kWe).

AECL estimates construction schedule (time from Contract Effective Date (CED) to end of commissioning) for the next EC 6 as 66 months. Experience with recent projects in China and Korea are between 69 and 77 months. For an EC 6 in Armenia, a construction schedule of 72 months is estimated.

The only construction cost estimates for the current model VVER 1000 designs provided by ASE was a range of $1,800 to 2,000/kWe for the AES 92. The estimate did not disclose what scope is covered by the estimate or when the estimate was established. It is assumed the estimate was established in 2006 since it somewhat higher than the cost estimates for the Koodankulam project in India(6) and Tianwan project in China(7), which were published in 2004. It is further assumed that the ASE estimate is for a two unit plant. Another assumption is that the estimate covers only the supplier's scope of equipment and services and does not include owners cost, which are typically about 15% of project costs. Based on these assumptions, the ASE $/kWe estimate for AES 92 was adjusted as follows:

- ASE estimate: $2,000
- Owner scope (15%): $300
- Escalation 2006-2007 (7.4%): $171
- Single unit factor (13.6%): $337
- Adjusted estimate: $2,808/kWe

Based on the adjusted estimate, the estimated construction cost for a single unit AES 92 with net generation capacity of 1000 MWe is $2.8 billion (2007 dollars). To this estimate must be added the cost for Armenia specific features:

- Upgrade of pumping station and piping: The pumping station and 7.5 km pipe lines that bring makeup cooling water from the Sevjur River and reservoir to the plant will need to be replaced at an estimated cost of $20 million.
- Seismic upgrade: The AES 92 plant design is based on 0.24g safe shutdown earthquake. The higher seismic hazard at ANPP site will require seismic isolators or other modification to the standard design, estimated at $140 million.

Based on these additional features, the estimated total construction cost would be $2.97 billion (2007 dollars) for an AES 92 plant with 1,000 MWe net generation capacity (($2,968/kWe).

AES provided an estimated construction time of 54 months for the AES 92 design. The construction of the Tianwan units I and II in China required 78 months and 81 months respectively. For an AES 92 in Armenia, a construction schedule of 72 months is estimated.

Capital Spending Profile

The timing of construction costs has a significant impact on the total charges for interest during construction. For each of the candidate NPP designs discussed above, a construction schedule of 72 months can be reasonably estimated. A typical spending profile for the construction period is shown in table 1.4. The spending shown for month zero is money spent before the start of construction including purchase of long lead equipment, preparation of licensing and permitting applications, and contractor mobilization payments.

Table 1-4, Spending Profile for NPP Capital Costs

Months	0	1-12	13-24	25-36	37-48	49-60	60-72
Percent of total cost	8.00%	20.5%	23.5%	20.5%	11.5%	11.0%	5.0%

Construction Cost Escalation

The overnight construction costs for all types of power plants have increased substantially over recent years. In the electricity generation sector, all technologies have experienced substantial construction cost increases in the past three years, from NPPs to wind power projects. Between January 1, 2004, and January 1, 2007, the cost of constructing steam generating units in the US increased by 25 percent, more than triple the rate of inflation over the same time period[8]. The four primary sources of the increase in power plant costs are:

- Material input costs, including the cost of raw physical inputs, such as steel and cement as well as increased costs of components manufactured from these inputs (e.g., transformers, turbines, pumps). For example, the price of various metals, including steel, copper and aluminum, has increased significantly in the last few years as a result of high global demand and increased production costs. The price of cement has also risen substantially in the past few years.
- Shop and fabrication capacity for manufactured components has not increased relative to current demand. Many components of power plants, including large components like turbines, condensers, and transformers, are manufactured as special orders to coincide with particular construction projects. Because many of these components are not held in large inventories, the overall capacity of their manufacturers can influence the prices obtained and the length of time between order and delivery. Manufactured components of generating facilities, (e.g., large pressure vessels, condensers, pumps, valves) have increased sharply since 2004.
- Cost of construction field labor, both unskilled and craft labor. A significant component of power plant construction costs is labor—both unskilled labor as well as craft labor such as welders, pipe fitters, and electricians. While less severe than commodity cost increases, increased labor costs contributed to the overall construction cost increases because of their substantial share in overall power plant construction costs.
- The market for large construction project management, i.e., the queuing and bidding for projects. Increased worldwide demand for power plants and other electric infrastructure projects means that major Engineering, Procurement and Construction (EPC) firms have a growing backlog of utility infrastructure projects in the pipeline. The growth in construction project backlogs reduces the competitiveness of EPC bids for future projects, which raises overall project cost.

The rate of escalation for power plant construction costs over the next ten years is difficult to predict. The number of nuclear plant projects being constructed during this period is expected to increase substantially, putting more pressure on prices. At the same time, suppliers can be expected to increase capacity and new suppliers will enter the market as prices and demand increase. In the US, Japan, and Europe, utilities and suppliers are beginning aggressive programs to train new workers, which can be expected to alleviate some of the labor shortages. A general economic slowdown may have the effect of slowing the growth in material costs. However, it can be expected that power plant construction costs will continue to increase at a rate higher than inflation. It is recommended that for estimating future construction costs, an escalation rate of 4% above the forecast inflation rate should be used.

Operating Costs

The primary operating costs for an NPP include the cost for operations and maintenance (O&M) and fuel. Annual O&M cost includes staff wages, repair parts, and consumable supplies. Costs for decommissioning and disposal of spent fuel disposal, while not operating costs, are usually accumulated on an annual basis in order to assure adequate funding of these activities after the plant is shut down and no longer producing revenue from electricity sales.

An annual O&M cost for the AP1000 in the US is estimated by Westinghouse as $80-$90 million per year for a single unit. Over 50% of this cost is wages and benefits for an operating staff of 600 people. If this same number of staff were used in Armenia, where wages are much lower than the US, the O&M cost would be substantially less. An annual cost of $59 million O&M cost for the AP1000.

Nuclear fuel cost for the AP1000 is estimated in the FPL cost estimate at $0..44 - 0.55 per million BTU, which is equivalent to about $5/MWh. This value is considered a realistic point estimate. Cost for spent fuel storage and disposal in Armenia is estimated between $0.69 and $1.31/MWh in section 5 of this Initial Planning Study. The midpoint of this range, $1/MWh should be used as the point estimate for AP1000 spent fuel disposal. Westinghouse estimates the cost of decommissioning a single unit site as about $500 million (2007 dollars). Based on a 60 year plant life and investment at a higher rate than escalation costs, this translates to about $5 million/year in contributions to the decommissioning fund.

ASE did not provide any information on the AES 92 operating costs. It can be assumed that the operating costs for AES 92 would be similar to those of the AP1000.

A summary of estimated costs for the three candidate NPP designs is provided in table 1.4.

Table 1-4, Summary of NPP Construction and Operating Cost Estimates

	NPP Design		
Cost Element	**CANDU EC 6**	**AP1000**	**AES 92**
Construction cost (Billion $)	1.94	3.73	2.97
Construction cost ($/kWe)	2,985	3,342	2,968
O&M Cost (Million $/year)	47	59	59
Fuel Purchase ($/MWh)	2.73	5	5
Fuel Disposal ($/MWh)	5.	1.	1.
Decommissioning Fund Contribution (Million $/year)	4	5	5

1.5 EVALUATION OF CANDIDATE SUPPLIERS

Based on the results of the survey, each of the three candidate NPP designs would be suitable for Armenia. Each design has completed a safety review by the nuclear regulator in its country of origin. They each have a similar seismic design basis, which will need to be modified to the seismic hazard of the ANPP site. The estimated capital and operating costs on a per MW basis are all within the range of uncertainty of the estimates. The estimated construction schedules are the same.

The EC 6 design has a number of unique features that are would be beneficial in the situation of Armenia, which are summarized as follows:

- Smaller size. The smaller generation capacity of the EC 6 is a much better match to Armenia's electric demand than either of the other candidate designs. As discussed in IPS section 3, upon startup in 2017, a 1,000 MWe plant is expected to operate at only 70 percent capacity to meet the domestic Armenia demand. The EC 6 would operate at 89 percent capacity. The ability to operate at a high capacity factor is essential to the economics of a nuclear generating station. As Armenia's electrical demand grows in the future, a second EC 6 unit could be built. A two unit plant provides more flexibility and reliability for a small grid such as in Armenia. If one unit goes offline, the other unit could supply most of the domestic energy demand.
- Load following capability. The EC 6 has rapid load following capability down to 60 % power, which is an important characteristic for the Armenian system with its large variations in daily load.
- Fuel diversity: The use of natural uranium or alternative fuels widens the source of supply and results in a lower fuel cost. Because there is no need for uranium enrichment, the EC 6 fuel is not impacted by potential increases in the cost of enrichment services. If significant uranium deposits are found in Armenia, fuel could be manufactured locally, enhancing energy security. There is also the potential to use recovered uranium from the spent fuel of the ANPP for the EC 6. There are a relativly large number of manufacturers of EC-6 fuel that ensures competition among suppliers. Although the volume of EC 6 fuel is much greater than for a PWR, a six month supply of fuel can be transported on a single large cargo aircraft.
- No reactor vessel. The EC 6 design uses pressure tubes in a calandria rather than a large pressure vessel to hold the fuel. This has two benefits for operations in Armenia. (1) It allows on-power refueling, resulting in potentially higher capacity factors. The top performing CANDU 6 units have achieved capacity factors in excess of 96 percent. [(2)] The use of a pressure tube reactor eliminates the need for a large reactor vessel, which will be difficult to transport into Armenia. The heaviest component in the EC 6 design is considerably smaller than for the PWR designs.

There are two disadvantages to the EC 6 design. Following a plant trip, there is a delay of about 36 hours before the plant can be restarted. This situation will not be experienced very often because the EC 6 design can accept a 100% load reduction without trip. However, if it were to occur, it will create a problem because the nuclear unit will normally supply a large portion of the system load. The other disadvantage is the need to replace the pressure tubes of the reactor after about 30 years of operation. Complete replacement of all pressure tubes requires an outage of up to one year, which would make the plant unavailable during the winter peak demand period. AECL has a program to develop methods for tube replacement on an incremental basis, such that an one year outage would not be required. This would not be such a serious problem for a two unit plant, where the schedules for the retubing outage could be adjusted to ensure one unit was always available.

Besides technical features, the EC 6 plant has a substantial advantage in reducing the risk of the project. EC 6 is a widely used design for which a supply chain has already been established. This eliminates the risk of construction delays due to problems with equipment suppliers, such as those currently being experienced by the Olkiluoto NPP project in Finland. The supply chain also assures that repair parts will be available when the plant is in operation. Because of the recent successful experience of AECL in completing construction projects on a turn key, fixed price basis, the risk of project cost over runs and schedule delays is minimal. The extensive operating experience of the existing CANDU fleet reduces the risk that the plant will have operational problems and provides a valuable resource for technical support through the CANDU Owner's Group. As discussed in IPS section 6, the reduction in project risk is a very important aspect in attracting financing at reasonable rates.

The primary advantage of the AP 1000 design is the relative simplicity of the safety systems. Besides significant improvement in the level of safety, this simplicity will provide operational and economic benefits. The passive systems have substantially fewer pumps, valves, controls, and other components than a conventional PWR. Also, there is no need for the large network of safety support systems needed in typical nuclear plants, such as AC power, ventilation, cooling water systems and seismic buildings to house these components. Simplification of plant systems, combined with increased plant operating margins, reduces the actions required by the operator. The AP1000 has 50 percent fewer valves, 83 percent less piping, 87 percent less control cable, 35 percent fewer pumps and 50 percent less seismic building volume than a similarly sized conventional plant. These reductions in equipment and bulk quantities lead to major savings in plant costs and construction schedules.

On a technical basis, the primary disadvantage of the AP1000 is its relative large capacity and size. Although large capacity NPPs are generally more economical in a large grid, in the small electrical system of Armenia, that capacity may not be usable at times. The very large and heavy components of the AP1000 will also be a challenge to transport into Armenia by road.

The principal advantage of the AES 92 design is it is provided by ASE, which already has a strong relationship with Armenia. The existing relationship should contribute to the availability of support services, and technology transfer provisions. Also developing the regulatory program for the new plant will be much simpler because the Armenia nuclear regulatory authority is already familiar with Russian safety regulations and design standards. One disadvantage of the AES 92 is that has a lower seismic design basis, which will require more enhancements to meet Armenia conditions.

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APPENDIX A: RESPONSES TO NUCLEAR PLANT VENDOR SURVEY QUESTIONNAIRE

Survey Response from Atomic Energy of Canada Limited

1. Discussion of any export limitations, or restrictions on providing detailed component design information, analysis details, and computational programs and source codes

Canadian Nuclear Safety Commission (CNSC) controls the import and export of nuclear materials and other prescribed substances, equipment and technology. Canada has undertaken nuclear cooperation only with those states that have signed a Nuclear Cooperation Agreement (NCA) with Canada. The NCA contains several assurances including:

- A non-explosive use commitment;
- A provision for fall-back safeguards;
- Retransfer, enrichment and reprocessing controls; and,
- Assurance of adequate physical protection measures.

Since 1976 Canada has engaged in nuclear cooperation only with states that have ratified the Treaty on the Non-Proliferation of Nuclear Weapons (NPT) or have taken an equivalent binding step and accepted International Atomic Energy Agency (IAEA) safeguards on the full scope of their nuclear activities.

2. Seismic design criteria

The CANDU 6 structures have a robust design for seismic events. Based on our experience, the CANDU 6 structures can withstand a DBE (SSE in the US) with a horizontal peak ground acceleration of 0.3 g and slightly higher without expensive design changes to the structure. The DBE for the Akkuyu (Turkey) site has a peak ground acceleration of 0.25g and hence the equipment and the structures do not require any major modifications for this level.

However, the problem is that the equipment will have difficulty in qualifying, withstanding the earthquake and operating during and after the event, for DBE of higher than 0.3g. In particular, the Fuelling Machines will have difficulty in qualification above 0.3g. For a site such as ANPP, with DBE between 0.35g to 0.5g, AECL's preferred option would be to place the critical Reactor Building on seismic isolators which would isolate the building significantly from a seismic event. This would result in the qualification of the equipment and the structure for 0.5g without major structural changes above the base slab of the Reactor Building. The cost of the isolators is not known but may be in the range of $100 m.

3. Load following capability

Considerable data is available documenting deep load changes (down to 60% and back to 100%) in the Bruce B and Embalse stations provides substantial data to confirm the load following capabilities of CANDU reactors. The plant power-maneuvering rate is limited by the turbine design, and is typically 5 to 10 percent of full power per minute. During normal plant operation, the reactor power may reduce to 60 percent of full power at rates up to 10 percent of full power per minute. The power may be held at the new lower level, indefinitely. Return to full power can be accomplished within three hours.

4. Interface requirements with the electric grid including power interconnect diversity, requirement for redundant supplies and transient limitations.

No response

5. Black start capability and tolerance for total loss of off-site power

The unit is capable of reaching 100 percent net electrical output from a cold shutdown within 12 hours. In the event of a temporary or extended loss of line(s) to the grid, the unit can continue to run and supply its own power requirements. The turbine steam bypass to the condenser is capable of accepting the steam flow during loss of line or turbine trip. Following a shutdown from sustained full power operation, the reactor can be restarted within 22 minutes (the poison override time) and returned to full power operation. Otherwise, a ‘poison-out’ period of about 36 hours results, after which the reactor can be restarted.

6. Capital investment costs

Overnight Capital (2 unit turnkey plant) is $2,317 per kWe net including all owner costs

7. Nuclear fuel cycle costs

Fuel cost:
Front End $2.73 / MWh
Back End $1.64 / MWh

8. Operation and maintenance (O&M) costs and estimated professional, technician, and crafts staffing requirements for operation and maintenance

Annual O&M for 2 unit = Labor cost of 843 Staff plus $68.14 M

The O&M cost includes provisions for:

- plant maintenance costs (materials, labor and heavy water makeup)
- support costs (head office, external services)
- outage costs (labor, material and services)
- on-going capital improvements as expense
- other (taxes, insurance and other fees)

9. Scope, schedule, and estimated cost of major life cycle refurbishment tasks

The design life for current CANDU 6 plants is 40 years. However, recent review of the operating CANDU 6 plants, indicate that an operating life in excess of 60 years is probable. The 60-year operating life can be achieved in a single plant shutdown at around mid-life for a duration of 12 months or less to perform mid-life modernization and refurbishing, to include the replacement of the pressure tubes and the steam generators. Pressure tube replacement cost estimate is about $300 M for EC6

10. Estimate of owner’s construction cost elements not included in supplier scope

The owner’s cost is the cost outside the vendor’s scope of supply:
- ·project approvals, permits, licenses,
- ·owner’s project team (contract, administration, etc),
- ·site preparation, including site services and access roads,

- infrastructure and construction indirects (water, electricity during construction),
- owner's facilities - switchyard (main station connection and grid
- connection), guard house, administration building (includes capital equipment (simulator)),
- ·training of owner's staff and their participation in commissioning, and security.

11. Decommissioning cost

$790 M for 2 units.

12. Construction time and overall project schedule

Current CANDU 6 projects use a 70-month project schedule (contract effective to in-service) and a 54-month construction schedule. The Quinshan Phase III, Unit 1 and 2 project has successfully achieved milestones consistent with this.

13. Construction staffing levels, including identification of critical craft requirements, and identification of critical on site component assembly operations (such as major pressure vessel assembly

For 2 unit Quinshan the construction workforce was 1000 local workers with 46 foreign supervisors.

14. Projected unit availability and refueling intervals

Online refueling. Plant Availability Factor:90% Outage for Maintenance 25 days once every 2 years per unit

15. Dimensions and weight of major components in "as shipped" configuration

See attached table. Largest component is Calandria @ 9 meters, 250 ton. Heaviest is Moisture Separator Reheater @ 350 ton

16. Programs for domestic participation and technology transfer

No response

17. Fuel strategy, scope of supply and services

CANDU fuel cycle options of current interest include: Natural uranium (NU), Slightly Enriched Uranium (SEU), Recovered Uranium (0.9%U235) (RU), Direct Use of spent LWR fuel In CANDU (DUPIC), the Thorium/U233 Cycles and the Transuranic mix.

18. Training of owner's staff for construction, commissioning, operation and maintenance, and support for on-site training facilities

For Quinshan, operating staff of 232 was trained in Canada

19. Critical spares, wear parts, and consumables

No response

20. Terms of service contracts

No response

21. Status of design certification or licensing in the country of origin and other countries

CANDU 6 meets the requirements of the Canadian Nuclear Safety Commission (CNSC). There are two operating CANDU 6 plants in Canada (Point Lepreau and Gentilly-2). CANDU 6 units have also been successfully licensed in Argentina, Romania, South Korea, and China. It also complies with IAEA design guides.

22. Construction and operating experience of existing plants, including support for owners groups and formal operating experience feedback programs

With eleven CANDU 6 units in operation and over 100 cumulative years of operation, CANDU 6 is a modern and proven design available for immediate construction. CANDU owners group very active in sharing OE and developing common solutions.

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

23. Identification of long lead time components

Few if any. CANDU 6 design is well known and supply chain is already established

24. Estimated time from contract award to startup

EC6 has a 69 months project schedule from contract effective date to in-service for the 1st unit. The 2nd unit will take an extra 9 months to complete

25. Estimate of construction payment schedule

The indicative disbursement schedules for a 2 unit EC6 project are:

Months	**0**	**1-6**	**7-18**	**19-30**	**31-42**	**43-54**	**55-56**	**57-78-**
Percent of total cost	**8.00%**	**9.4%**	**24.1%**	**23.4%**	**15%**	**9.8%**	**5.6%**	**4.7%**

26. Estimated quantities of low and intermediate radioactive waste, including waste from major refurbishment tasks

The average annual volume of contaminated liquid wastes are approximately 18,000 m3 per year. Contaminated or potentially contaminated liquids are collected in the liquid waste collection tanks.
Annual Estimated Solid Radioactive Waste
Spent Resin 7 m3
Low level combustible wastes 22 m3
Low level non-combustible waste 9 m3
Filters 2 m3
Other wastes 1 m3
Total 41 m3

27. New fuel storage capacity and capability for additional storage to insure against supply disruption

Not limited

28. Identity of all fuel suppliers with experience supplying this NPP fuel

Country	City	Company
China	Baotou	CNNC
Pakistan	Chashma	PAEC
Argentina	Ezeiza	CNEA
India	Hyderabad	NFC
Canada	Peterborough	GE Canada
Romania	Pitesti	SNN
Canada	Port Hope	ZPI
Canada	Toronto	GE Canada
Korea, Rep. of	Yuseong	KNFC

29. Any nationally imposed restrictions on fuel ownership, retention, reprocessing, etc.

Canada does not accept return of spent fuel

30. Extent of support for public information and outreach programs

No response

31. Capability for plant operation at a range of final heat sink conditions (e.g.: dry cooling), impact on plant parameters and safety studies, and ability/willingness to incorporate dry cooling in the design

Can use dry cooling with efficiency penalty

Other

Current CANDU 6 spent fuel bay capacity with the most up-to-date storage rack design can store up to 10 years of spent fuel. The dry spent fuel storage system is an air-cooled concrete module that houses a number of metal canisters containing spent fuel. This arrangement provides highly efficient heat rejection, excellent shielding and complete structural soundness. Dry spent fuel storage can be applied as soon as after 6 years pool storage, and is licensed locally.

Quinshan is a 2 unit CANDU 6 plant that was built by a team of AECL, Bechtel, Hitachi, and Chinese partner. AECL was the lead for this fixed price EPC contract. Plant was constructed ahead of schedule and under budget. A major reason for success of the construction project was that CANDU 6 design is well known and supply chain is already established.

Summary of Largest Components Requiring Shipment to an EC6 Construction Site

Item No.	Name of Equipment	Qty	Gross Weight (metric tons)	Overall Dims (m)	Comments
1	Personnel Airlock	1	30.0	4.67 x 3.96 x 3.15	
2	Equipment Airlock	1	110.0	7.5 dia. X 12.5 L	
3	Stainless Steel Liner for Fuel Transfer Structure	1	37.5	Part A 4.89 x 3.35 x 9.1 Part B 7.62 x 2.44 x 9.7	Constructed in 2 parts (A & B) Probably constructed at site. Transportation within site boundary only
4	Degasser Condenser	1	49.0	2.23 Dia. X 7.52 L	
5	Feeder Header Frame	2	55.0	7.29 x 6.61 x 2.92	
6	SB 100 ton Crane	1	27.0 largest piece	3.4 W. x 2.2 H. 13.85 L Largest crate.	Shipped in 6 crates
7	Moderator Heat Exchanger	2	56.0	1.93 Dia. x 10.37 L	
8	RB Boiler Room Crane	1	20.0 largest piece	6 x 21 L. Largest crate	Shipped in 5 crates
9	ECC Tank	3	104.0	4.2 Dia. x 12.7 L	
10	Pressurizer	1	110.0	2.13 Dia. x 16.15 L	
11	Steam Generator	4	200.0	4.3 (2.9) Dia. x 20 L	
12	Calandria	1	250.0	8.53 W. x 8.96 H. 8.48 L	
13	PHT Pump Motor	4	46.0	4.2 x 4.11 x 4.37 H	
14	TB trusses or main crane beam	2		47 L	Longest component. Transportation probably within the site boundary only
15	Standby Diesel Generators	2	150.0	7 x 5 x 5 H	
16	Turbine Generator Rotor	1	150.0	15 x 4 x 4 H	
17	Turbine Generator Stator	1	320.0	12 x 6 x 6 H	
18	Moisture Separator Reheater	2	350.0	25 x 5 x 5	
19	Deaerator Storage Tank	1	85.0	15 x 5 x 5	
20	Main Output Transformer	3	150.0	8 x 5 x 8	3 single phase transformers. Could possibly be one

					transformer @ 450.0 t
21	Condenser Modules	2 or 3	200.0	15 x 5 x 5	
22	Main Feed Water Pumps	3	50.0		
23	Condensate Storage Tank	1		4 x 4 x 28	

Note: Items such as S/G's, Calandria, Pressurizer, Degasser Condenser do not have packaging as such except for shrink wrap protection and support cradles.

Survey Response from Westinghouse

1. Discussion of any export limitations, or restrictions on providing detailed component design information, analysis details, and computational programs and source codes

Armenia & USA would need to execute a nuclear technology export agreement under provisions of Atomic Energy Act. Technology export would also need to be approved under the guidelines of the Nuclear Suppliers Group.

2. Seismic design criteria

AP1000 design is based on 0.3 g acceleration for the Safe Shutdown Earthquake (SSE). Because of the broad response spectra, there is some conservatism, and analyses of a particular site's conditions may justify a higher value. They have investigated use of seismic isolators at a site in Japan to achieve a 0.8 g SSE. Adding seismic isolators would add well over $100m to the cost.

3. Load following capability

AP1000 can accept an instantaneous 10% power drop. Can ramp from 100% to 50% over two hour period.

4. Interface requirements with the electric grid including power interconnect diversity, requirement for redundant supplies and transient limitations.

Because AP1000 does not rely on AC power for safety, it does not have any special grid interface requirements. The design uses a Toshiba turbine generator which is particularly robust to changes in voltage and frequency.

5. Black start capability and tolerance for total loss of off-site power.

AP1000 can accept a loss of offsite power (LOSP) without trip, using steam dumps. However, to have black start capability, a gas turbine would need to be added to the design.

6. Capital investment costs

The current estimate for the supplier scope in the US is $3,500 per kw capacity for a 2 unit plant. This is very much dependence on local market conditions for labor and commodities. For example in the US, management and supervision cost is 20% of total labor cost. In some foreign locations, it is 50% of labor cost because local labor cost is lower but the cost of sending supervisors to the country is much higher. Transportation costs must also be considered. Cost could be $4,000/kw.

7. Nuclear fuel cycle costs

Fuel costs are estimated at $7-$10 per MWh at current uranium prices of $100/pound. The fuel is up to 5% enriched and produces about 62 GWdays/ton of uranium.

8. Operation and maintenance (O&M) costs and estimated professional, technician, and crafts staffing requirements for operation and maintenance

O&M staff for 2 units in US is estimated as 800-900 people. For single unit it would be about 600 people. O&M cost is primarily staff wages and is estimated as $80-90m/year in US.

9. Scope, schedule, and estimated cost of major life cycle refurbishment tasks

May require turbine generator overhaul. Steam Generators are designed for replacement but are designed to last 60 years.

10. Estimate of owner's construction cost elements not included in supplier scope.

The major cost is wages for operating staff during construction for training. Owner's cost estimated as 10-15% on top of supplier's total overnight construction cost.

11. Decommissioning cost

Decommissioning estimate is $500m in current year dollars.

12. Construction time and overall project schedule

Estimate 6 years from contract signing to commercial operation. This assumes that:

- The site permits and licensing are in place
- The long lead components are ordered at least 2 years before contract signing

13. Construction staffing levels, including identification of critical craft requirements, and identification of critical on site component assembly operations (such as major pressure vessel assembly

Construction workforce estimated at 1,500 – 2000 people. Critical skills are welders, heavy lift crane operators, nondestructive test/inspection technicians, and construction management

14. Projected unit availability and refueling intervals

Estimated average unit availability over 20 years is 93.4%, including refueling and a major outage for turbine generator refurbishment. Equivalent forced outage rate is estimated to be no more than 1.5%. Refueling is 17 days every 18 months.

15. Dimensions and weight of major components in "as shipped" configuration

The largest component is the steam generator (SG) at 650 tons. Other large components are the reactor pressure vessel (RPV), transformers, generator stator, and large tanks. It is not feasible to assemble the RPV and SG on site. However, construction modules may be assembled locally. Transport by large trailers is feasible but often requires road reinforcement and widening and bridge reinforcement.

16. Programs for domestic participation and technology transfer

Westinghouse will buy from any local sources available. One area of local participation is assembly of construction modules, worth about $200 M. The license to the technology is available but very expensive.

17. Fuel strategy, scope of supply and services

Typically Westinghouse manufactures fuel using enriched Uranium provided by the customer. However, they could buy the uranium and provide complete fuel service. US regulations prohibit them from accepting the return of spent fuel.

18. Training of owner's staff for construction, commissioning, operation and maintenance, and support for on-site training facilities

Westinghouse provides full training for operations and maintenance and will oversee the NPP startup.

19. Critical spares, wear parts, and consumables

Westinghouse can provide critical spares and consumables for additional price ($200-300 M). Spares include reactor coolant pump, turbine & generator rotors). Westinghouse recommends sharing spares inventory with other plants, one of the advantages of the standard plant design.

20. Terms of service contracts

Westinghouse offers full service contracts at competitive prices. Westinghouse also provides the owner with all technical information needed to operate, maintain, and modify the plant. However, technical information is proprietary and not transferable to other service providers.

21. Status of design certification or licensing in the country of origin and other countries

AP1000 has a design certification from the US NRC. A revision to the design certification to address issues that have come up in the US licensing process is under review and should be approved by 2010. In China, construction permit should be approved by 2009, operating license by 2013. In UK design certification review is in progress, expected by 2010. AP1000 has a certificate of compliance with the European Utility Requirements Document.

22. Construction and operating experience of existing plants, including support for owners groups and formal operating experience feedback programs

Operating experience factored into design. Many of the major components are from existing PWR design (e.g., SG is from system 80+, fuel is from earlier Westinghouse design). Owner participation in AP1000 and PWR owner's groups is encouraged.

23. Identification of long lead time components

There are 25 long lead items include RPV, SG, reactor coolant pump, containment liner. These items cost about $100 M and must be ordered at least 2 years before the beginning of the construction period.

24. Estimated time from contract award to startup

AP1000 estimates a 6 year construction schedule based on modular construction. However, long lead items must be ordered 2 years before the start of this schedule. US utilities are ordering now or a plant they would like to startup in 2016 (8 years)

25. Estimate of construction payment schedule

Estimate 1/3 of total cost spent by the time that concrete pour begins.

26. Estimated quantities of low and intermediate radioactive waste, including waste from major refurbishment tasks

AP1000 produces 5,800 cubic feet of LLW per year (uncompacted). Because the reactor control uses mechanical rod movement rather than changing Boron concentration, the amount of liquid radwaste is much less than previous design PWRs. The LLW waste estimate does not include replaced steam generators.

27. New fuel storage capacity and capability for additional storage to insure against supply disruption

Reload requires 65-72 assemblies. Design includes new fuel storage for 72 assemblies. However, new fuel could also be stored in spent fuel pool. Spent fuel pool holds 18 years worth of fuel (950 assemblies).

28. Identity of all fuel suppliers with experience supplying this NPP fuel

Fuel for Westinghouse NPPs is sold by Westinghouse, AREVA and maybe Russia in the future. Other manufacturers are in Korea, Japan, Spain, China,

29. Any nationally imposed restrictions on fuel ownership, retention, reprocessing, etc.

US regulations do not allow return of spent fuel. See question 1 on US 123 agreement

30. Extent of support for public information and outreach programs

Westinghouse would provide support to public outreach but did not participate in EIA in China.

31. Capability for plant operation at a range of final heat sink conditions (e.g.: dry cooling), impact on plant parameters and safety studies, and ability/willingness to incorporate dry cooling in the design.

The standard design uses natural draft wet cooling tower. There is no safety reason why dry or hybrid cooling could not be used, but it would cost more and have lower electrical output/efficiency.

Other notes:

Plant could be built as a Build Own Operate (BOO) project, hiring a nuclear utility company to operate the plant. The O&M cost would be 2-3 times higher.

Westinghouse is considering a project in South Africa, 70 KM from nearest port. There are shortages of skilled labor, no housing for foreign labor, inadequate roads. Housing may cost as much as $1B. Road improvements will cost hundreds of million. Road transport will require several weeks for each of heavy component.

The turbine generator for the standard design is manufactured by Toshiba. However, the AP1000 in China will use the MHI design, for which they have a license to manufacture locally.

Modular construction: Modules can be built on site; however, this requires extensive lay down areas and heavy load paths. Several cranes with 1,500 ton capacity are needed.

In a meeting with NEI, it was suggested that there was limited risk in ordering AP1000 long lead components because they could be resold to other owners if the project is not built.

Japan Steel and Dousan are the only current suppliers of Forgings for RPV. However, other suppliers (e.g., Ansaldo, MHI, BWI Canada, IHI) are developing capability. Other supply chain constraints are SG Tubes, stainless steel components and Reactor coolant pumps.

Survey Response from ATOMSTROYEXPORT

Main characteristics of nuclear power unit AES-92

It is provided, that capacity of the new nuclear power unit will be up to 1000МВт (). The Russian nuclear power unit of the atomic power station AES - 92 can be the prototype. This power unit with reactor ВВЭР-1000 has the license for construction. This power unit has following characteristics:

Technical characteristics
Capacity (thermal), MW – 3000
Capacity (electrical), MW – 1068
Life time, years – 60
Possibility to construct on every type of grounds without changing the lay-out and building design
Estimated frequency of core heavy damages during the accidents, 5.6 10-8 per year
Plant efficiency coefficient (estimated), % (brutto) - 35.6
Load factor, % - 0.92
Electric energy production, mlrd kWh - 7.5 – 8.0

Safety Systems

- Safety systems building structure - 4 X100%
- Passive and active systems availability
- “Defense in depth” protection
- External impact protection: airplane, tsunami, earthquake, flooding
- Melted fuel trap (core catcher)

Economic characteristics

The capital cost is 48600-54000/kw in Russian ruble, which was converted into USD using conversion rate of 1$ = 27 rub. (1800 – 2000USD). This estimate was prepared in either 2005 or 2006. This cost includes cost of cooling tower but doesn’t include cost of owner.

Construction time, months - 54

General parameters of WWER-1000 types V-466, V-428 and V-412.

Characteristics	Reactor type		
	V-466	V-428	V-412
Reactor plant			
Rated thermal power of reactor, MWth	3000	3012	3012
Electric capacity of NPP (gross), MWe	1046	1060	1000
Number of loops	4	4	4
Reactor lifetime, years	60	40	30
Annual hours of operation at rated power (effective), hours	7800	7000	7000
Reactor			
Coolant absolute pressure on exit from core at rated power, MPa	15.7	15.7	15.74
Rated coolant flow rate through reactor, m3/hour	86000	86400	86000
Coolant temperature on outlet from reactor, ^{0}C, rated	321	321	321
Coolant temperature on inlet into reactor, ^{0}C, rated	291	291	291
Reactor temperature range, ^{0}C, rated	30	30	30
Reactor pressure vessel			
Diameter of cylindrical part of pressure vessel near core, mm	4150	4150	4150
Thickness of wall, mm	192,5	192,5	192,5
Thickness of anti-corrosion facing, mm	9	8	8
Length, mm	10897	11185	11185
Material	15X2HMFA	15X2HMFA	15X2HMFA
Number of assemblies in the core	163	163	163
Equivalent diameter of core, mm	3160	3160	3160
Height of the core in cool condition, mm	3530	3530	3530
Number of fuel elements in an assembly	311	311	311
Maximum linear thermal flow (capacity) of fuel element, W/cm	448	448	448
Maximum enrichment of fuel with U235 isotope, %	4,4	up to 4,4	up to 4,4
Fuel burnup in an assembly (in steady-state conditions), MWday/kgU	47	43	43
Steam generator			
Internal diameter, mm	4000	4000	4000
Height (length), mm	13840	13840	13840
Type	horizontal	horizontal	horizontal
Number of tubes	10978	10978	10978
Heat exchange surface, m^2	6038	6038	6038
Layout	corridor	staggered	staggered
Rated steam output, tons/hour	1470	1470	1470
Rated pressure, MPa	6,27	6,27	6,27
Diameter and thickness of heat exchange tubes, mm	16x1,5	16x1,5	16x1,5
Material of tubes	08X18H10T	08X18H10T	08X18H10T

Reactor cooling pump			
Type	GCNA-1391	GCNA-1391	GCNA-1391
Displacement, m^3/hour	22000	22000	22000
Head, MPa	0.588	0.588	0.588
Power rating, kW	6800	6800	6800
Power rating (hot water), kW, no more than	5100	5100	5100
Reactor main loop			
Internal diameter of hot (cold) pipeline, mm	850	850	850
Thickness of pipeline, mm	70	70	70
Pressurizer			
Pressure, MPa	15,7	15,6	15,6
Volume, (total) m^3	79	79	79
Volume of water during power operation, m^3	55	55	55
Power rating of heaters (total), kW	2520	2520	2520
Reactor Emergency Cooling System Containers			
Rated pressure, MPa	5,9	5,9	5,9
Volume, m^3	60	60	60

2. REVIEW OF NUCLEAR FUEL SUPPLY OPTIONS

This section studies the plans, costs, and schedules of major fuel suppliers to provide fuel for alternative NPP designs. An important attribute of the nuclear generation expansion option in Armenia is that it would reduce the country's vulnerability to short-term interruptions in imported fossil fuel supplies. However, it should be recognized that without appropriate planning the new nuclear unit could make Armenia highly dependent on a single source of nuclear fuel. The ability to establish relationships for nuclear fuel from alternative sources that would not be susceptible to political or business interruption is a critical factor in achieving the energy independence offered by a replacement nuclear plant.

2.1 SURVEY OF VENDOR FUEL PROGRAMS

This section will survey the current suppliers of nuclear fuel for the candidate NPP designs selected in IPS section 1,.For each candidate NPP design, companies or countries offering nuclear fuel assemblies for that design will be identified.

There are several steps in the production of nuclear fuel. These steps also vary depending on the whether the fuel is composed of natural uranium or enriched uranium. In the case of natural uranium (CANDU) fuel the steps are:

- Mining the uranium
- Milling the uranium to produce “yellow cake” (U3O8)
- Production of UO2 or UO3 from the “yellow cake” and sintering it into pellets
- Assembling the pellets into Zirconium clad fuel rods and grouping the rods into bundles

For enriched fuel the steps are:

- Mining the uranium
- Milling the uranium to produce “yellow cake” (U3O8)
- Conversion of the “yellow cake” to Uranium Hexafluoride gas
- Enrichment of the Uranium Hexafluoride gas
- Production of Uranium Dioxide from the Uranium Hexafluoride gas and sintering it into pellets
- Assembling the pellets into Zirconium clad fuel rods and grouping the rods into bundles

Seventeen countries perform mining and milling operations; the largest producers being Canada, Australia, Kazakhstan, Namibia, Niger and the Russian Federation. Eight countries perform conversion activities; the largest being the United States, France, Canada, the Russian Federation and the United Kingdom. Twelve countries perform enrichment; the largest being the United States, France, the Russian Federation, Netherlands, and the United Kingdom. Fuel fabrication is done in eighteen countries; the largest being the United States, the Russian Federation, France, Canada, Japan and the United Kingdom.[1]

[1] IAEA Technical Report Series number 425 Country Nuclear Fuel Cycle Profiles second edition 2005, p 11-12

In 2002, similar to today, nuclear fuel requirements were estimated to be 10,000 tons HM (heavy metal) while total fabrication capacity was estimated to be 19,000 t HM. Despite this over production, a number of countries are starting to set up their own fuel fabrication programs.[2]

The World Nuclear Association predicts that the worldwide demand for fuel fabrication won't approach today's capacity until about 2025. And they see the fabrication capacity as adequate, although the enrichment capacity will be strained.[3]

Over the last 15 years the world supply of nuclear fuel has been supplemented by downblending of weapons grade uranium. This process does not require enrichment and the cost of enrichment has been suppressed. Low prices have prevented suppliers from building new enrichment facilities. Now the availability of weapons grade uranium is less, so the demand for enrichment is growing. Although new enrichment facilities are planned in the US and Europe, they are not yet available. The absence of new operating enrichment facilities coupled with increased demand will cause prices to rise before additional facilities are commissioned and equilibrium returns to the enrichment market. One author predicts that enrichment costs will rise from today's price of $140/SWU to $340/SWU before the market stabilizes.[4] Even if the price of uranium remains stable at its current level, $60/pound, escalating enrichment costs could drive the price of enriched fuel up by 50%.

Table 2-1 presents a list of fuel fabricating facilities around the world:[5]

While some countries rely on a single source of fuel several have diversified their sources of supply. For example; Spain has uranium supply contracts with Australia, Canada, Russian Federation, Namibia, Niger, Portugal and South Africa; conversion contracts with Cameco (Canada), Converdyn (USA), Comurhex (France), Minatom (Russian Federation), and Springfields (UK); Enrichment contracts with Eurodif (France), Minatom, Urenco (Netherlands), and USEC (USA); and fabrication contracts with Belgonucleaire (Belgium), Framatome (France), GNF (Japan), Columbia (USA), Springfields, Vasteras (Sweden).[6] Numerous sources of supply provide assurance that fuel will be available.

[2] ibid
[3] The Global Nuclear Fuel Market –Supply and Demand 2005-2030, Henry Maeda, Itochu International
[4] Economics of Nuclear Power and Proliferation Risks in a Carbon Restrained World, Jim Harding, Report to the US Senate, June 2007
[5] IAEA Technical Report Series number 425 Country Nuclear Fuel Cycle Profiles second edition 2005, p 18-20

[6] [6] IAEA Technical Report Series number 425 Country Nuclear Fuel Cycle Profiles second edition 2005, p 76

Table 2-1, Fuel Fabrication Facilities

Country	Facility Name	Operator	Fuel Type	Capacity (MTU/year)
Argentina	Ezeiza	CNEA	PHWR	150
Belgium	Dessel	Framatome	LWR	400
Belgium	Dessel	Belgonucleaire	MOX/LWR	35
Brazil	Resende	INB	LWR	280
Canada	Toronto	GE Canada	PHWR	1,300
Canada	Peterborough	GE Canada	PHWR	1,200
Canada	Port Hope	(ZPI)	PHWR	1,500
China	Yibin	CNNC	LWR	200
China	Baotou	CNNC	PHWR	200
France	Romans	Framatome	LWR	1,400
France	Cadarache	Cogema	MOX/LWR	40
France	Marcoule-Melox	Cogema	MOX/LWR	145
Germany	Lingen	Framatome	LWR	650
India	Hyderabad	NFC	BWR	24
India	Hyderabad	NFC	PHWR	570
Japan	Tokai-Mura	MNF	PWR	440
Japan	Kumatori-machi	NFI	PWR	284
Japan	Tokai-Mura	NFI	BWR	200
Japan	Kurihama	GNF J	BWR	750
Japan	Tokai-Mura	JNC	ATR/FBR	15
Kazakhstan	UST-Kamenogorsk	Ulba	VVER, RBMK	2,000
Korea, Rep of	Yuseong	KNFC	PWR, PHWR	400
Korea, Rep. of	Yuseong	KNFC	PHWR	400
Pakistan	Chashma	PAEC	PHWR	20
Romania	Pitesti	SNN	PHWR	110
Russian Fed.	Elektrosal	JSC TVEL	LWR	1,520
Russian Fed.	Novosibirsk	JSC TVEL	LWR	1,000
Spain	Juzbado	ENDUSA	LWR	400
Sweden	Vasteras	Westinghouse	LWR	600
UK	Sellafield	BNFL	MOX/LWR	120
USA	Columbia	Westinghouse	PWR	1,250
USA	Lynchburg	Framatome	PWR	400
USA	Richland	Framatome	LWR	700
USA	Wilmington	GE Nuclear Fuel	BWR	1,100

2.2 NUCLEAR FUEL PRICE FORECAST

This section will present estimate of nuclear fuel prices for the period 2016 through 2025.

Nuclear fuel costs are based on the cost of uranium fuel, the zirconium cladding and the costs associated with processing the uranium to form the final product. For PWRs, the processing components are uranium mining and milling, conversion to UF6, enrichment, reconversion to U O2, fuel fabrication, shipping costs, and interest costs on fuel in inventory, and spent fuel management and disposition. A 2003 MIT study calculated a 5 mill (half a cent) per kilowatt hour cost for all these steps, based on then-current uranium prices of $13.60/lb. Spot market prices for uranium in early June 2007 were $135/lb, tripling since October 2006. Today prices have dropped to about $60 per pound. One author made this observation the recent volatility the uranium market:

"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 (1998-2013) with natural uranium.

The most expensive step in the fabrication process is enrichment. The World Nuclear Association has stated that Enrichment accounts for almost half of the cost of nuclear fuel (in LWR plants) and about 5% of the total cost of the electricity generated.[7] This would indicate that natural uranium fuel (which doesn't require enrichment, uses less uranium but does require a greater amount of material formed into fuel bundles) for a Candu-6 unit would cost much less than fuel for a PWR..

Worldwide uranium production is about 60 % of current uranium demand. The balance is being provided by downblending of weapons grade uranium now in storage. 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."[8]

In 2007 prices were high, but even then predictions were that the price will stabilize and possibly drop. Lehman Brothers, the investment company, saw that the high prices were the result of limited investment; in 2007 they projected:

"We project average prices for all of 2007 at $120 and forecast a peak of $165-$170 by 2009, followed by a drop toward $60 over the next half decade."[9] As it happened the prices peaked at $138 per pound and then began to drop. On June 13, 2008 the spot price for uranium stood at $59.13.

As with other energy commodities, uranium has drawn interest from speculators. This interest has resulted in an increase in prices. In previous years, down blending of weapons grade uranium for use in power plants has augmented supplies and kept investment in new sources of uranium limited. The high prices of 2007 spurred investment to the point that supplies should exceed demand in the coming years and cause prices to remain moderate. An estimated price of $60 per pound is reasonable.

2.3 GLOBAL NUCLEAR ENERGY PARTNERSHIP

This section will evaluate the potential developments by the Global Nuclear Energy Partnership (GNEP) that could positively affect the security of nuclear fuel supply to Armenia. Under the GNEP, a consortium of nations with advanced nuclear technologies would provide fuel needs of other countries, while minimizing proliferation concerns and eliminating the need to invest in the complete fuel cycle. In cooperation with the International Atomic Energy Agency, participating nations would develop international

[7] World Nuclear Association, Briefing Paper on Fuel June 2007

[8] Economics of New Nuclear Power and Proliferation Risks in a Carbon Constrained World, Jim Harding, June 2007

[9] Lehman Brother, Uranium Price Outlook, June 8, 2007

agreements to ensure reliable access to nuclear fuel. These agreements could involve a leasing approach, where fuel suppliers would provide fresh fuel but retain responsibility for the final disposition of the spent fuel. The GNEP may also include establishment of a nuclear "fuel bank" - where the IAEA administers a nuclear fuel reserve to assure a back-up supply for power reactors throughout the world on a non-discriminatory, non-political basis. Armenia has agreed to participate in the planned International Enrichment Center at Angarsk, Russia for enrichment services for ANPP fuel. Developments at the Angarsk facility are part of Russia's participation in the GNEP program.

The Global Nuclear Energy Partnership (GNEP) is a plan to provide an assured source of nuclear fuel for all countries while providing disincentives to the proliferation of nuclear weapons. It was initiated by the USA, but has gained support from the IAEA and the Russian Federation. The program has since been joined by Japan, China and other countries. As mentioned in section 5 of this report, Armenia has already joined some of the Russian initiatives to provide an assured source of nuclear fuel. Participation in the GNEP efforts would likewise be a wise step in preparation for the future.

Under the GNEP program, the back end of the fuel cycle would include reprocessing of fuel to extract usable nuclear fuel. New technology would be developed so that the final waste is incapable of being used in nuclear weapons. Full actinide recycling will also reduce the amount of material disposed of as high level waste.

The World Nuclear Association has summarized the front end of the proposed GNEP fuel cycle in this way:

“Under GNEP, so-called 'fuel-cycle' nations would provide assured supplies of enriched nuclear fuel to client nations, which would generate electricity before returning the used fuel. It would then undergo advanced reprocessing so that uranium and plutonium it contained, plus long-lived minor actinides, could be recycled in advanced nuclear power reactors. Waste volumes and radiological longevity would be greatly reduced by this process, and the wastes would end up either in the fuel cycle or user countries. Nuclear materials would never be outside the strictest controls, overseen by the IAEA. Two sensitive processes in particular would not need to be employed in most countries: enrichment and reprocessing. The limitation on these, by commercial dissuasion rather than outright prohibition, is at the heart of GNEP strategy. GNEP member nations would be assured of reliable and economic fuel supply under some IAEA arrangement yet to be specified.”[10]

At present the members of the GNEP are; USA, China, France, Japan, Russia, Australia, Kazakhstan, Bulgaria, Hungary, Lithuania, Romania, Slovenia, Ukraine, Poland, Ghana, Jordan, Canada, South Korea ,Italy and the UK. The group includes many of the world's major uranium mining, enriching, reprocessing and fabricating nations.

The World Nuclear Association goes on to say:

“GNEP envisages the development of comprehensive fuel services, including such options as fuel leasing, to begin addressing the challenges of reliable fuel supply while maximizing non-proliferation benefits. The establishment of comprehensive and reliable fuel services, including spent fuel disposition options, will create an all-encompassing approach to nuclear power for nations seeking the benefits of nuclear power without the need to establish indigenous fuel cycle facilities. It is through enabling such a framework that GNEP makes its primary contribution to reducing proliferation risk….

[10] World Nuclear Association, February 2008

For countries that have no existing nuclear power infrastructure, GNEP partners can share knowledge and experience to enable developing countries to make informed policy decisions on whether, when, and how to pursue nuclear power without any need to establish sensitive fuel cycle facilities themselves."[11]

As the GNEP program comes to maturity, it is likely that the international community will expect countries to participate in GNEP. It is strongly suggested that Armenia participate in the GNEP initiative. In this way Armenia will be prepared as the international community moves toward these multinational facilities.

2.4 FABRICATION OF CANDU FUEL

In April 2008, Russia and Armenia signed a treaty to set up a joint venture for the exploration and mining of uranium and other minerals in Armenia. Armenian uranium reserves are estimated at 30,000-60,000 metric tons. With a domestic supply of uranium and an EC 6 type nuclear unit that does not require enriched fuel, Armenia could achieve a high degree of energy independence by fabricating its own fuel. This section will discuss in more detail the feasibility of establishing a facility in Armenia for fabrication of CANDU type reactors from local uranium resources. Most CANDU reactors use natural uranium so there is no need for enrichment. The section will include a description of the processing facilities required for conversion of uranium ore into CANDU fuel, a budgetary cost estimate for construction and operation of these facilities, and discussion of technological, commercial, or political issues related to such a project.

The CANDU-6 uses natural uranium. Since enrichment is unnecessary, the steps in the process are simpler. These steps are:

- Mining and conversion to yellowcake (U3O8)
- Conversion of the U3O8 to UO2 or UO#
- Fabrication of the UO2 or UO3 into fuel elements

Several countries operating CANDU power reactors fabricate their own fuel. From table 2.1, it is observed that this is true of Canada, Romania, Argentina, China, Korea, Pakistan and India.

In the case of Romania, all steps in the fuel process are done domestically. This decision of the former political regime was not based on economics but on the desire for a completely independent source of fuel. The uranium is mined in Romania and fabrication of nuclear fuel is the responsibility of SNN who operate the Nuclear Fuel Factory (FCN) – Pitesti. This facility is licensed by ZPI Canada (Zircatec Precision Industries) for CANDU-PHWR type NPP fuel fabrication. At present, FCN-Pitesti is the supplier of the nuclear fuel required for Cernavoda NPP-Unit 1 and Cernavoda NPP-Unit 2 which started operation in 2007. It is planned that Pitesti FCN will supply the nuclear fuel for units 3 and 4 starting with 2013 respective 2014. Note that the increase of FCN capacity will enhance the efficiency of the factory and consequently lowers the costs related to nuclear fuel. The Nuclear Fuel Plant Pitesti is qualified by AECL as a CANDU 6 fuel manufacturer. Prior to expansion, the capacity of the plant is 90 tons per year and 23 bundles per day respectively, In 2002, FCN Pitesti manufactured 5,779 nuclear fuel bundles, so the total number of fuel bundles produced between 1994-2002 is 33,068, containing 620 tons of natural uranium. Initially Romanian fuel suffered a high number of fuel defects, however recent production has been nearly defect free.

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[11] ibid

In order to safely operate its fuel facilities, Romania has a strong legal framework to control nuclear material and nuclear activities. The Law 111/1996 republished is the Law on the safe deployment of nuclear activities. In 2000 Romania ratified the Additional Protocol to the Safeguards Agreement and in 2001 has submitted to IAEA the Initial Declaration. In respect to physical protection of nuclear material National Commission for Nuclear Activities Control coordinates at national level the activities regarding preventing and combating illicit trafficking with nuclear material and radioactive sources. The Romanian nuclear fuel cycle contains uranium mines, a conversion plant, nuclear fuel plant, CANDU NPP, nuclear research institutes, heavy water plant. Romania controls the import /export activities concerning nuclear material, non nuclear material and equipment through the National Commission for Nuclear Activities Control and Ministry of Foreign Affairs – National Agency for Export Import Control for Strategic Products

In respect of non proliferation policy, Romania is a non-nuclear weapon state which uses the nuclear energy only for peaceful purposes, shows transparency for all nuclear activities, controls strictly export and import with nuclear material, non nuclear material and equipment, combats the illicit trafficking with nuclear material and radioactive sources. Also, Romania as a member of IAEA from 1957 has ratified international treaties, agreements and conventions:

- Romania acceded to the 1963 Vienna Convention on Nuclear Third Part Liability on 29 December 1992, which entered into force on 29 March 1993.

- Romania acceded to the 1988 Joint Protocol on 29 December 1992, which entered into force on 29 March 1993.

- 1963 Treaty Banning Nuclear Weapons Tests in the Atmosphere, in Outer Space and under Water, ratified on 23 November 1963 and entered into force on 23 December 1993;

- 1968 Treaty on the Non-Proliferation of Nuclear Weapons, ratified on 4 February 1970 and entered into force on 5 March 1970;

- 1971 Treaty on the Prohibition of the Emplacement of Nuclear Weapons and other Weapons of Mass Destruction on the Sea Bed and the Ocean Floor and in the Subsoil thereof, ratified on 10 July 1972 and entered into force on the same date;

- Safeguards Agreement between Romania and IAEA entered in force in 1972;

- 1979 Convention on the Physical Protection of Nuclear Material, ratified on 23 November 1993 and entered into force on 23 December 1993;

- 1986 Convention on Early Notification of a Nuclear Accident acceded to on 12 June 1990 and entered into force on 13 July 1990;

- 1986 Convention on Assistance in Case of a Nuclear Accident or Radiological Emergency acceded to on 12 June 1990 and entered into force on 13 July 1990;

- 1994 Convention on Nuclear Safety, was ratified on 1 June 1995 and entered into force on 24 October 1996;

- 1996 Comprehensive Nuclear-Test-Ban Treaty, signed on 24 September 1996;

- 1997 Joint Convention on the Safety of Spent Fuel Management and on the Safety of Radioactive Waste Management, signed on 30 September 1997

- 1997 Protocol to Amend the Vienna Convention on Civil a Liability for Nuclear Damage, signed on 30 September 1997;

- 1997 Convention on Supplementary Compensation for Nuclear Damage, signed on 30 September 1997;

- 1997 Joint Convention on the Safety of Spent Fuel Management and on the Safety of Radioactive Waste Management signed on 30 September 1997 and entered into force on 18 June 2001;

- 1999 the Additional Protocol signed on June 1999 and ratified on July 2000;To avoid the diversion of nuclear material from peaceful use, Romania has ratified Agreements at governmental level with Canada and USA and at National Safety Authorities level with Republic of Argentina, Canada, France, Greece, Hungary, Germany, Republic of Korea and USA.

The Republic of Korea (Korea) depends on outside suppliers for uranium, in fact Korea has invested in uranium suppliers in Australia, USA, Russia and Canada. Korea operates both PWR and PHWR plants. For the PWR plants they obtain enrichment services from; France, USA, Russia and Netherlands. The fuel is fabricated in Korea.[12]

Cost of a fuel fabrication plant for Armenia can be estimated from the cost of other facilities. In Brazil the Resende Unit 1, Brazil's 100 MTU/year fuel fabrication plant, was completed in 1985 with a total investment of approximately $17 million. In 1998, a 400 MTU/year South Korean fuel fabrication plant was built for approximately $400 million. For a single unit CANDU plant annual fuel consumption would be about 90 MTU/yr and the construction cost is estimated to be $100 million dollars. Additional operating costs involve zirconium cladding, which must be obtained from sources outside Armenia.

The OECD estimated the cost of fuel fabrication as $47-$83 /kgU[13]. Using $65/kgU, midpoint of the range, and an annual fuel consumption of 90 MTU/yr; the annual cost of fabrication is $5.85 million. Ignoring substantial operating and material costs (Zirconium cost is about 150 $/kg) it would take over 17 years to pay back the cost of a fuel fabrication facility. In addition the IAEA has reported:

"Oversupply (in fuel fabrication) still exists and it is likely that additional facilities will be shut down in the near future to bring supply and demand into balance."[14]

While heavy water is not used in the fabrication of fuel, it is necessary as a moderator in CANDU plants. If Armenia wished to develop a completely independent CANDU fuel source, a heavy water plant would be necessary. Based on the IAEA's Nuclear Fuel Cycle Information System database the capital cost of a heavy water plant is between $10 and $25 million and the cost of heavy water produced is $300/kg.[15]

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[12] IAEA,Technical Report Series number 425 Country Nuclear Fuel Cycle Profiles second edition 2005

[13] Trends in the nuclear Fuel Cycle; Economic, Environmental and Social Aspects, NEA for OECD, 2001

[14] IAEA,Technical Report Series number 425 Country Nuclear Fuel Cycle Profiles second edition 2005, p. 4

[15] IAEA, ''Transcript of the Director General's Press Statement on Activities in Iran,'' Aug. 11, 2005; IAEA, GOV/2004/11; IAEA, GOV/2004/34; IAEA, GOV/2004/60; Alistair Miller, ''Heavy Water: A

2.5 CONCLUSIONS AND RECOMMENDATIONS

From the review on Supply of Nuclear Fuel several conclusions and recommendations can be drawn.

Conclusions:

- The supply of uranium will be adequate throughout the life of a new nuclear plant. The current higher cost of uranium is expanding mining and milling operations and new mining and milling operations will offset the decrease in supply of uranium from nuclear weapons stockpiles.
- The cost of uranium has been volatile; however the present spot price of $60/pound is expected to remain in force.
- Enrichment capability is expected to be tight for the foreseeable future and the price of these services will rise until additional capacity comes on stream.
- GNEP initiatives will continue to advance which will provide some assurance of a reliable source of supply.
- Even without GNEP numerous countries provide a source of supply.
- The fabrication of natural uranium fuel in Armenia is feasible although the cost may be somewhat higher than purchase of fuel from established supplies.

Recommendations:

- Armenia should participate in the GNEP initiatives.
- Armenia should diversify its sources of uranium, enrichment, and fabrication among several countries and sources.

Manufacturer's Guide for the Hydrogen Century,'' Canadian Nuclear Society Bulletin 22 (Feb. 2001),Bwww.cns-snc.ca/ Bulletin/A_Miller_Heavy_Water.pdf_

3. REVIEW OF THE REGIONAL EXPORT POSSIBILITIES AND GRID REQUIREMENTS

The objective of this study is to investigate the potential and limitations of electric power export to neighboring countries. The study assumes that a new 1000 MW nuclear unit is placed in service in 2017 and that ANPP unit 2 is shutdown for decommissioning at the same time. It is also assumed that the production cost of the new unit will be between $0.075-0.127/kWh.

3.1 DETERMINATION OF SEASONAL EXPORT CAPACITY

The objective of this section is to determine the excess generation from the new nuclear unit that will be available for export. The 2006 Least Cost Generation Plan (LCGP) [1] provided forecasts for growth in peak load and annual consumption for the domestic power system in Armenia through 2025. The forecasts were based on the patterns of load growth over the period 1998 through 2004 as well as assumptions on economic growth in Armenia. The LCGP forecasts included three scenarios: High Growth, Reference, and Low Growth. The assumptions of each forecast are summarized in table 3.1. The forecasts differed by the rate of growth in energy consumption and associated system peak load. The High Growth Scenario was characterized by higher development of industries, due to which annual load factor rises from current 50.0% to 55.1%. In the Reference scenario, it was assumed that there would be growth in residential and commercial consumption, while industrial sector would also increase consumption, but not as substantially as the High Growth Scenario. For this reason, the average annual load factor would reach 52.8%. The Low Growth scenario was based on the assumption that no substantial changes would occur in the structure of electric power consumption, and the load factor would remain at the same level as it is now, around 50.0%.

Table 3-1, Summary of Demand Scenarios (2005-2025) Analyzed in the LCGP

	Base Year 2005	Low Growth Scenario 2025	Reference Scenario 2025	High Growth Scenario 2025
Total Domestic Consumption (GWh)	4,150	6,540	8,048	9,862
Gross Peak Demand (MW)	1,293	1,902	2,198	2,569
Average Annual Load Factor (%)	49.7%	49.9%	52.8%	55.1%
Average Annual Growth Rate of Consumption	na	2.4%	3.4%	4.4%
Average Annual Growth Rate of Peak Demand (%)	na	1.9%	2.6%	3.4%
An accelerated growth rate is assumed for all scenarios during the first half of forecast period. The average annual growth of generation during 2005-2015 is projected to be 5.9%, 4.4% and 3.4% for High Growth, Reference, and Low Growth Case scenarios respectively				

To check the validity of the LCGP forecast, an update analyses was performed using data from various reports and sources including Public Service Regulatory Commission (PSRC), Settlement Center CJSC and Electric Power System Operator (EPSO). The data for the period of 2005 through 2007 were analyzed to evaluate the accuracy and consistency of the LCGP demand forecasts. The analyses results indicate that the growth rate for Total Domestic Consumption over the period was 5.2 %, which is between the accelerated growth rates for the High Growth and Reference scenarios of the LCGP. The results also show that the system operated at an average 54.3% load factor during the period, which is also between the rates for the High Growth and Reference scenarios of the LCGP. Based on these results, it is concluded that the LCGP growth forecasts are valid for characterizing future domestic demand in Armenia.

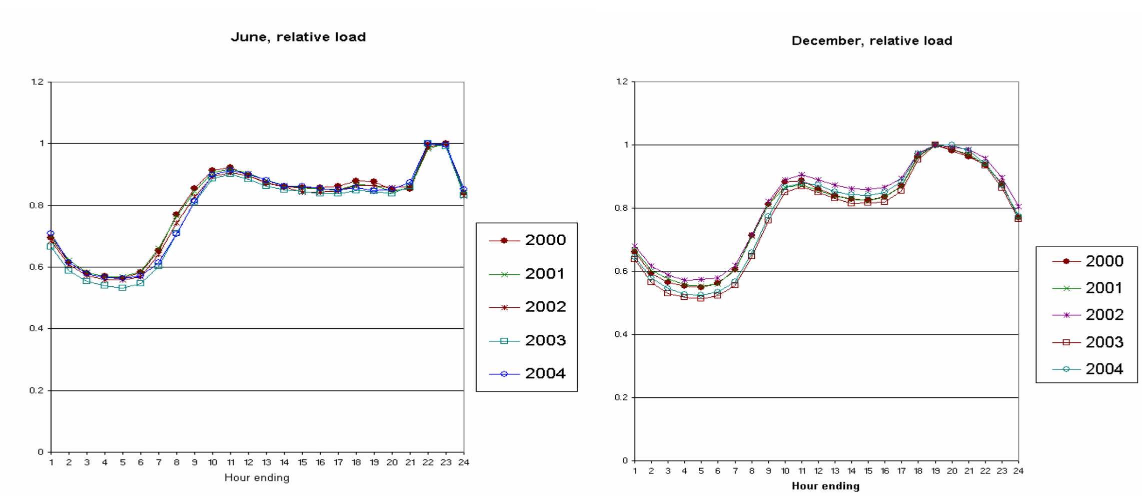
The forecast for Armenia's domestic demand for the period 2017 through 2030 from the LCGP Reference scenario is shown in table 3.2. The estimates for 2026 through 2030 are based on extrapolation of the growth rates for the Reference case scenario. The growth rate in total consumption is higher than the rate for peak load because it is expected that much of the growth comes from industrial and commercial customers, which do not contribute as much to the peak load.

Table 3-2, LCGP Reference Scenario Electric Demand Forecast (2017-2030)

	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Domestic Consumption (GWh)	5876	6112	6357	6612	6877	7153	7439	7738	8048	8371	8706	9056	9419	9796
Peak Load (MW)	1733	1785	1839	1895	1952	2011	2071	2134	2198	2264	2333	2403	2475	2550
Minimum Load (MW)	533	554	576	599	623	649	675	702	730	759	789	821	854	888

The table also shows the estimated minimum demand for each year. As described in the LCGP, the electric demand in Armenia varies considerably by season and by time of day. For example, for 2000 through 2004, the peak demand in June averaged 60% of the December peak demand. Typical daily load profiles for June and December are shown in Figure 3.1. The load shapes exhibit typical features of the load that is specific to a system with predominant residential load. The early morning load is about 50% of the daily peak in the evening. Based on these figures, the annual minimum load is estimated to be 30% of the peak load.

Figure 3-1, Typical Daily Load Profiles for June and December



To determine export capacity, it is assumed that the net generation capacity of the new nuclear unit is 1,000 MW with a 90 percent capacity factor. It is further assumed that dispatch practices will ensure that no more than 75 percent of the Armenia system load will be supplied by the new nuclear unit. The Armenia system is protected by a load shedding scheme that allows a single generator to provide up to 75 percent of system load. It can be seen from table 3.2 that 75% of the system minimum load is much less than the 1,000 MW capacity of the new nuclear unit. The capacity of the new unit during the off peak periods would then be available for export.

To estimate the energy available for export, an annual load duration curve for Armenia domestic load were developed from analysis of recent system operating data. A load duration curve displays the percentage of time during a period that the load is in excess of a specified value. Estimates for the Armenia domestic load were developed from analyses of 2005 through 2007 data, extrapolated to future years based on the LCGP Reference scenario growth rates. The estimated domestic load duration curves for 2017 and 2030 are shown in figures 3.2 and 3.3. The curves also show the load duration for the new nuclear unit, under the constraint that it supplies no more than 75% of system load.

The load duration curves indicate that the new nuclear unit would operate for significant periods at less than full capacity to meet only the domestic Armenia demand. Without exporting power, the new nuclear unit would operate at full capacity for only a small portion of the year during 2017, with an average capacity factor of about 70%. The new unit is expected to be able to operate with at least a 90% capacity factor. Therefore, it could generate up to 1,750 GWh of electricity for export. By 2030, the domestic load is expected to have increased such that the new nuclear unit could operate at an average capacity factor of about 83%. This will still leave approximately 600 GWh for export.

It can be seen that under the Reference case assumptions, the ability to export electricity is essential to the economics of the new NPP project. Without exporting power, the forecast capacity factors are well below those needed for economical operation of a 1,000 MW nuclear unit.

Figure 3-2, Armenia Domestic Load Duration Curve (2017)

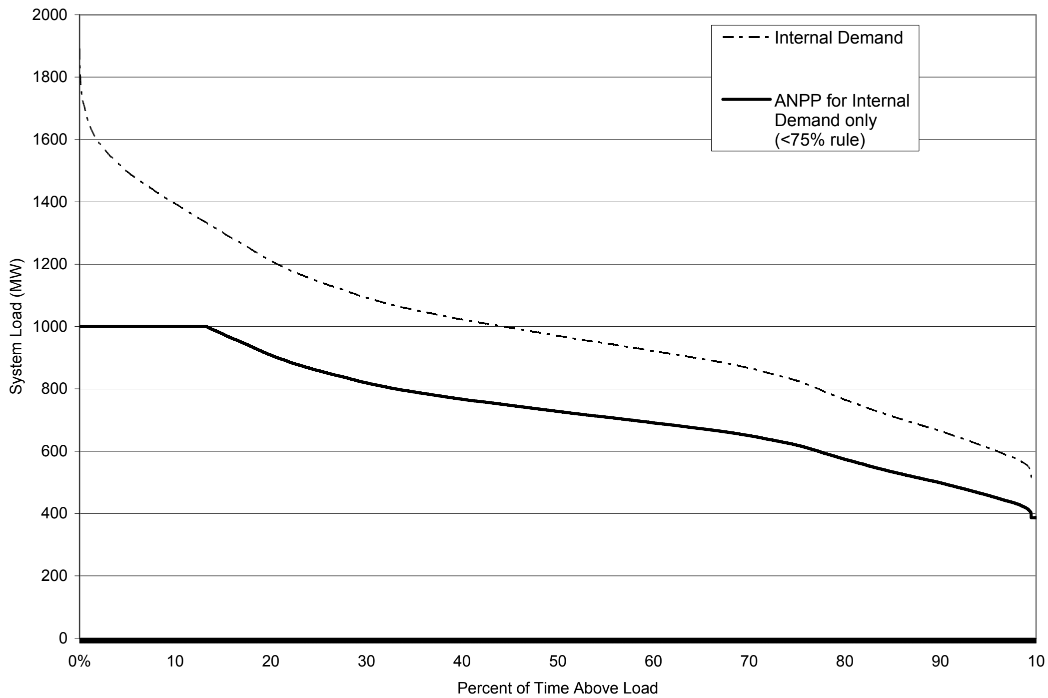
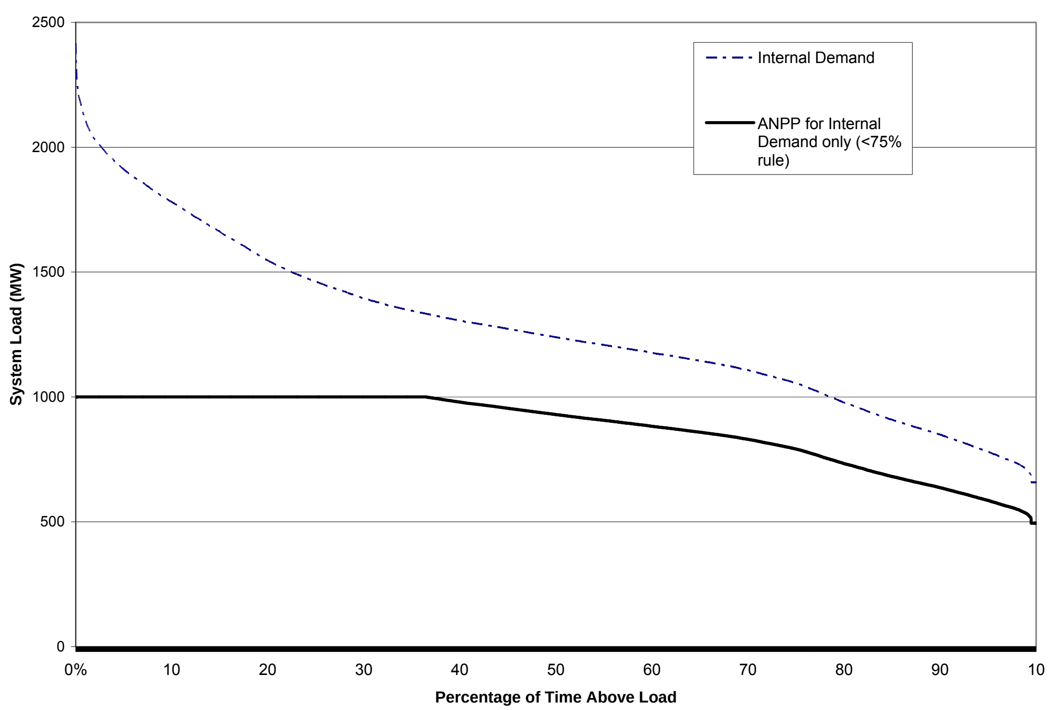


Figure 3-3, Armenia Domestic Load Duration Curve (2030)



In extrapolating the 2005 to 2007 load data to estimate future year load duration curves, it was assumed that the annual load shape of the Armenian power system will remain the same within the planning horizon. As discussed in the LCGP High Growth Scenario, increased electricity demand by industrial customers would be expected to flatten the annual load duration curve. This would provide more opportunity to operate the new nuclear unit at full capacity and reduce the amount of electricity available for export.

For the case of the EC 6 with MWe capacity, the new nuclear unit would operate at full capacity for over half of the year during 2017, with an average capacity factor of about 82%. This would leave 460 GWh available for export. By the year 2022, the EC 6 unit would be operating at 90% capacity factor, with no excess capacity available for export.

Another development that could significantly impact the utilization of the new unit for domestic load or export is pumped storage. Pumped storage would use the generation of the nuclear unit to pump water to a storage reservoir during periods of low electrical demand. The stored water would be released through a hydro generating station to meet peak demand. Such a system could level the daily load profiles for the Armenia system. A 1998 study [11] of a 140 MW pumped storage project on the Achbarinski Reservoir concluded that it would increase utilization of the existing ANPP by 640 GWh per year at a cost of about $40 million. Such a system would have an even larger impact for a 1000 MW nuclear unit. With a pumped storage plant, the amount of nuclear generation available for export would be substantially reduced. Armenia's MoENR is currently considering updated feasibility studies for other pumped storage projects.

3.2 DESCRIPTION OF REGIONAL POWER SYSTEMS

The objective of this section is to describe the power systems of neighboring countries as they relate to export potential.

Iran

The electrical demand in Iran has been growing at a rate of almost 9% per year over the period 2001 through 2006. During the same period, electricity generation in Iran has grown at about 7.5% per year.[2] Electric generation in Iran is approximately 90% from natural gas or oil fueled generation, with the remaining 10% from hydro power plants.[2] While Iran has a several modern combined cycle power plants, over half of its electric generation is from simple cycle gas turbines or steam plants, which are fairly inefficient. The estimated average efficiency for Iran's thermal generation is about 34 percent.[2]

Unlike Armenia, Iran's electric demand peaks in the summer period. Summer peak load is approximately 50% higher than the winter peak and some regions of Iran experience electricity supply shortages during the summer. The difference in peak demand periods creates the opportunity to export power from the new nuclear unit to Iran during periods of relatively low domestic consumption in Armenia.

Iran trades power with neighboring countries, exporting power to Iraq, Turkey, Pakistan, Azerbaijan, and Afghanistan while importing power from Armenia, and Turkmenistan. Iran has net power exports of approximately 28,000 GWh per year. Iran and Armenia recently signed an agreement to exchange Armenian electricity for Iranian natural gas at the rate of 3 kWh of electricity per cubic meter of gas. Based on the current price of gas to the Armenian border of $110/1000 cubic meter, [3] the exchange agreement is equivalent to about $0.037/kWh. However, as the price of gas to Armenia increases, the value of the exchange becomes much more favorable. As discussed in IPS section 6, the price of gas to Armenia is expected to escalate to at least 80 percent of the current price to Europe of $410/1000 cubic meter [(3)]. At this gas price, the value of the exchange would be over $0.10/kWh, within range of the expected production cost of the new nuclear unit.

The estimated volumes of electricity to be provided under this agreement are shown in table 3.3. The electricity available for export from the new nuclear unit would be much less than the amount called for in the agreement.

Table 3-3, Agreement between Iran and Armenia on Electricity for Gas Exchange

Time period		Electricity GWh
Stated in agreement	**Adjusted based on existing status of works**	
2014 - 2016	2017- 2019	5,250
2017 - 2018	2020 - 2021	6,000
2019 - 2026	2022 - 2029	6,900

The price of power generation in Iran was estimated by the World Bank as $0.036/kWh in 2004. [(4)] Because 90% of Iran's power is from gas fueled generation, the cost of electricity is closely linked to the price of gas. Based on the average heat rate of Iranian generation and the current European gas price of $410/1000 cubic meter, [(3)] the cost for generation in Iran should be over $0.10/kWh. Future generation costs in Iran are expected to increase in relation to the market price of gas.

If Iran's first nuclear power plant, Bushehr, becomes operational, its output will be less than three percent of the summer peak of Iran's electric system. This is not expected to have a significant effect of Iran's need for electricity imports from Armenia.

Georgia

Total installed generator capacity in Georgia is approximately 4,800 MW, but much of this capacity is not in operable condition. [(5)] The total hydroelectric capacity is 2,843 MW spread between 14 large scale plants and about 80 plants of less than 10 MW capacity each. In recent years, electricity has been generated primarily by hydroelectric facilities (81.4% on average since 2000) with the balance being generated by natural gas fired thermal power plants and imports from Russia and Azerbaijan. The Georgian government has expressed a strong formal commitment to expanding hydro generation capacity in coming years. Similar to Armenia, Georgia's electric load peaks in the winter when the availability of hydro power generation is low.

Georgia's electricity transmission network is already connected to neighboring countries of Turkey, Russia, Azerbaijan and Armenia. Expansion plans call for reinforcement of the Georgia-Russia-Azerbaijan loop and building a new connection to Turkey in order to increase transfer capacity. [(6)] In February 2008, Azerbaijan, Georgian and Turkish leaders agreed to construction of the 500 kV electricity transmission line which will link Azerbaijan with Turkey via Georgia. The system will increase the supply of the Azerbaijani electricity to Georgia, which is carried out according to the agreement signed between the two countries at the end of 2007. The planned system would allow the three countries and Russia to import and export electricity on a seasonal basis, evening out shortages and surpluses and ensuring the free exchange of electricity between the countries.

The current transmission lines between Georgia and Armenia have a capacity of 250 MW. A 170 km, high voltage transmission line between the Hrazdan substation in Armenia and the Qsani substation in Georgia with capacity of 500 MW is under construction.[6] With the new high voltage line, excess capacity of the new nuclear unit could be exported to Georgia. With the interconnection of this line to the planned 500kV line in Georgia, electricity could be exported to Azerbaijan and Turkey as well.

In the past, Armenia had an agreement to supply power to Georgia during the winter season, at a price of $0.028/kWh. This agreement was ended in 2006, when Armenia requested price increases to $0.053/kWh. The average generation tariff in Georgia in 2007 was $.031/kWh.[7] However, power imported from Armenia to Georgia would displace power generated at thermal power stations, for which the tariff was about $.063/kWh. This thermal power plant tariff is closely linked to the price of natural gas, so it is expected to increase in line with the cost of gas from Azerbaijan and Russia. With the growth of electricity demand in Georgia and continued natural gas price increases, power from the new nuclear unit would be cost competitive with Georgia's thermal power plants and Georgia could provide a market for export of electricity from Armenia. However, Georgia's peak demand is during the same period as Armenia, so there would be little capacity available from the new nuclear unit for export to Georgia.

Turkey

Hydro and lignite coal fueled generation are the primary energy resources of the power system of Turkey. Large loads are concentrated in the areas of western Turkey including Istanbul, İzmir and Ankara. Most of the hydro resources and a large lignite fields are located in eastern Turkey, so power has to be transmitted across the country via 400 kV lines.

Expansion plans in Turkey include construction of an additional 2,010 MW of hydro power capacity in eastern Turkey.[6] Turkey is also planning to build several NPPs over the next ten to 15 years. Transmission lines between eastern and western Turkey will also be strengthened. Turkey will also participate in the construction of the 500 kV electricity transmission line which will link Azerbaijan with Turkey via Georgia.

Turkey has applied for integration with the European Union for Coordination of Transmission of Electricity (UCTE) and its national system operator, together with UCTE, is conducting studies and tests to assess the technical feasibility of synchronous interconnection with the UCTE zone. It is constructing a high voltage line to connect with Greece.[6]

Power generation costs in eastern Turkey are relatively low, due to the availability of hydro power plants. The financial calculations for the 500 kV electricity transmission line assumed the price at the Turkish border $0.035/kWh.[8]

Turkey currently imports small amounts of power from Iran and Georgia. An agreement for sale of electricity by Armenia to Eastern Turkey was recently announced. With growth of electricity demand in eastern Turkey and Turkey's export of electricity to UCTE, Turkey may develop as a market for export of electricity from Armenia. There is an existing transmission line between Armenia and Turkey with capacity of 300 MW. However, this line has not been in operation for many years and must be refurbished. If Turkey's system enters synchronous connection with UCTE, the grid in eastern Turkey that is supplied from Armenia would have to be islanded from the rest of the Turkish grid. In the longer term, the path for large scale electricity export to Turkey would be through connection to the planned 500 kV electricity transmission line which will link Azerbaijan with Turkey via Georgia.

Azerbaijan

Azerbaijan's power sector has an installed generating capacity of approximately 5,500 MW. Eight state-owned thermal plants provide 80 percent of generating capacity. The country also has six hydroelectric plants, all of which are owned by the state. [9] Due to the recent startup of the BTC and SCP pipelines, power demand in Azerbaijan is growing. Without capacity growth to take advantage of the country's new fuel sources, Azerbaijan will continue to need to import electricity from its neighbors. On average, Azerbaijan imports roughly 2.1 GWh, slightly under 10 percent of its total consumption. In order to supply electricity to all parts of the country, Azerbaijan imports power from Russia, Turkey, Iran, and Georgia. Azerbaijan's imports 150,000 kWh from Iran and around 575,000 kWh from Turkey into the Nakhchivan Autonomous Republic (NAR).

Although Azerbaijan is net importer of electric power, power production in Azerbaijan is expected to increase in the near future with the construction of privately owned power plants fueled by natural gas. However, Azerbaijan gas reserves are not large and planned increases in exports may deplete these reserves within 20 - 30 years. In this scenario, Azerbaijan may become a market for power export by the year 2040, well within the life of the new nuclear unit.

There is an existing transmission line between Armenia and Azerbaijan with capacity of 420 MW. However, this line has not been in operation for many years. The path for electricity export to Azerbaijan would be through connection to the planned 500 kV electricity transmission line which will link Azerbaijan with Turkey via Georgia.

3.3 EVALUATION OF TRANSMISSION CAPACITY AND COST ESTIMATES

There are currently grid connections and agreements to exchange power with Iran and Georgia. However, transmission of large amounts of power to neighboring countries may require substantial improvements to the transmission lines in Armenia as well as in the other countries.

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

- Armenia- Iran, two 220 kV transmission lines that were built in 1997 and 2003 with 300- 450 MW capacity;
- Armenia-Georgia, one 220 kV transmission line with 250 MW capacity, and two 110 kV transmission lines with a total capacity of 100 MW;
- Armenia-Azerbaijan, one 330 KV line with 420 MW capacity, which is currently disconnected; and,
- Armenia-Turkey, one 220 KV line with 300 MW capacity, which is currently disconnected.

Currently the GoA is planning a significant expansion of existing transmission network. The major additions which will affect the electricity exchange capabilities with the neighboring power systems are the following.[10]:

- 400kV two-circuit line to transfer 1000MW from Armenia to Iran (Hrazdan TPP - Shinuair-Ahar) is under construction, which will be completed in 2010.
- 400kV one-circuit line to transfer 500MW from Armenia to Georgia (Hrazdan TPP - Qsani) is under construction, which will be completed in 2010.

Exporting the power from the new nuclear unit to Georgia and Iran will require completion of a 400 kV transmission line between the ANPP site and the Hrazdan substation. The length of this new transmission line will be about 100km. Based on recent cost studies of a high voltage transmission line in Georgia[8], the cost for high voltage transmission line construction ranges between $250,000/km to about $500,000/km.[8] Therefore, constructing the transmission line needed to export the power from the new nuclear unit will cost between $25 and $50 million. The transmission tariff needed to recover this cost, based on transmission of 1,000 GWh/year, is $ 0.004 - 0.009/kWh.

3.4 CONCLUSIONS

A new 1,000 MW nuclear unit will generate significantly more electricity than can be used to meet Armenia's domestic load. Because of large seasonal and daily variations in the domestic load, the plant would operate well below the expected 90% capacity factor if only domestic load is served. Therefore, electricity export is necessary for economical operation of the 1,000 MW plant.

Based on assumptions in the LCGP Reference scenario, a 1,000 MW nuclear unit operated at the 90% capacity factor would produce over 1,750 GWh available for export during the first year of operation in 2017. The electricity available for export will decrease as Armenia domestic load continues to grow. However, there will still be over 600 GWh available for export in 2030.

In the near term, the existing agreement with Iran for exchange of electricity for gas provides an assured market for electricity export from the new nuclear unit. The electricity available for export from the new nuclear unit would be less than half of the amount called for in the agreement. Iran's peak demand period during the summer corresponds to the period of low demand in Armenia. Although the value of gas received based on current gas price to Armenia is less than the expected production cost of the new nuclear unit, future escalation in gas price will make the return much higher. At the current European gas price, the value of exported electricity would be significantly above estimated nuclear production costs.

Armenia has developed plans for construction of the high voltage transmission lines necessary for power export to Iran and Georgia. The construction of a transmission line to connect the new nuclear unit to these 400kV lines is necessary to export the excess capacity of the new nuclear unit. This 400 kV transmission line is estimated to cost between $25 and $50 million, which will add less than 10% to the cost of electricity delivered to Iran.

It will be technologically feasible to export significant amounts of electricity to other neighboring countries of Georgia, Turkey, and Azerbaijan, particularly with the connection of the new high voltage transmission line to Georgia to the planned 500 kV transmission line linking Azerbaijan with Turkey via Georgia. Future growth in electricity demand in these countries and increases in natural gas prices should make the estimated production cost of the new nuclear unit competitive with other electric power resources available in these countries. However, peak demand in Georgia and eastern Turkey is during the same period as Armenia, so there would be little capacity available from the new nuclear unit for export to Georgia.

If future changes in the neighboring power systems reduce or eliminate Armenia's ability to export large amounts of electricity, an alternative approach to increasing the capacity factor of the nuclear unit is one or more pumped storage facilities. Previous feasibility studies have concluded that addition of pumped storage capability to existing hydro resources in Armenia can significantly increase utilization of the nuclear plant.

3.5 REFERENCES

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10. Mode Calculations for Development Scheme of Armenian Power System, Scientific Research Institute, CJSC, 2006

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4. ASSESSMENT OF THE NATIONAL INFRASTRUCTURE REQUIREMENTS VIS-À-VIS AVAILABLE INFRASTRUCTURE

This study, related to the proposed new nuclear power plant, will evaluate the infrastructure requirements, capabilities, constraints and development needs, and their costs. Specific topics include grid capacity and stability, transportation, industrial support, and technology transfer. This study will also examine site engineering characteristics that may affect the feasibility of construction of the new NPP, such as construction energy sources, water supplies, and transportation facilities.

4.1 SURVEY OF GRID CAPACITY AND STABILITY

Operating experience with NPPs in grids of limited capacity has shown that the safe and efficient utilization of the plant has been hindered by disturbances originating in the grid as well as by incompatibility between certain characteristics of the grid and those of the NPP. The risk for the NPP of the loss of grid stability is that the emergency systems of the plant maybe unnecessarily forced to rely on onsite diesel generators. The existence of a strong electrical grid is one feature of defense in depth for the safety of the NPP. If a weak grid is unavoidable, other measures should be taken to reestablish sufficient defense in depth; for example, additional sources of dedicated onsite power and greater capability for the plant to remain on line during grid fluctuations.

4.1.1 Current Characteristics of the power grid and Planned Additions

Armenia has a transmission network that has the capability to transport over 3000 MW of generation capacity and about 16,000 GWh of energy within Armenia and the neighboring countries. The transmission network is being rehabilitated as funding becomes available. Funding for these projects is being provided by Germany, The European Union, France, The World Bank, and others.[16] A $20 million investment in transmission and distribution substation equipment was provided by USAID from 1998 to 2001.

In 2005 the Armenian transmission network consisted of 1,527 km of 220 kV overhead lines and 14 substations as well as 3,083 km of 110 kV overhead lines and 119 substations.[17] At this time, the system is capable of transmitting and distributing electricity within the country. A number of studies have been done of the power grid, but little transient analysis has been done of the system that would exist at the time the proposed new plant is put in operation. PA Consulting is in the process of performing some of these transient analyses.

Existing regional interconnections are:

- Armenia- Iran, two 220 kV transmission lines that were built in 1997 and 2003/4 with 300- 450 MW capacity.
- Armenia-Georgia, one 220 kV transmission line with 250 MW capacity, and two 110 kV transmission lines with a total capacity of 100 MW.
- Armenia-Azerbaijan, one 330 kV line with 420 MW capacity, currently disconnected.
- Armenia-Turkey, one 220 kV line with 300 MW capacity, currently disconnected.

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[16] Existing Political Conditions and Economic Opportunities for Regional Power Systems Cooperation, Strategic Research Institute, Friedrich Ebert Stiftung, 2004 pages 22-23
[17] Energy View of BSEC Countries 2006 page 73

Planned additions to the network include: [18]

- A SCADA system to provide communication and control of the transmission system will be installed in two phases. In the first phase, the SCADA system will be installed in all 220 kV substations and at the generating plants. In the second phase the SCADA system will be installed in the 110 kV substations. Therefore the SCADA system will be installed at the ANPP location prior to new plant construction.
- A single 400 kV circuit from the substation at Hrazdan TPP to Georgia. For this line the design is done, agreement has been reached with the ministry and construction of this line will be started when funding is arranged. With high degree of certainty this transmission line is going to be built.
- Double circuit 400 KV line from the substation at Hrazdan TPP to Iran. There is a preliminary design, but not yet a working design. This line is part of an agreement between Armenia and Iran to swap electricity for natural gas and this agreement provides funding. With high degree of certainty this transmission line is going to be built.
- A substation at Hrazdan for the new 400 kV lines from Georgia and Iran. With high degree of certainty this transmission line is going to be built.
- Double 400 kV transmission line from the ANPP to the new 400 kV substation at Hrazdan TPP. This will be required for the new NPP, but since the new NPP is still being studied it is premature to state the design of this transmission line.

Armenia's interconnection with Iran is planned to be upgraded with new 400 kV double circuit overhead lines (Hrazdan-5 TPP- Shinuair-Ahar) that are expected to be completed in 2010 (with 1000 MW transmission capacity).[19] Iran and Armenia signed an MOU in June 2005 to implement a 400kV two-circuit transmission line project[20]: details are still being discussed. References[21] [22] have variously indicated the cost of this project to be between $40 to $90 million and the funding to come from commercial loans or "special funding schemes". During the same period another 400 kV single circuit overhead line (600 MW) between Armenia and Georgia (Hrazdan-5 TPP-Qsani) is planned to be constructed.[23] The addition of the 400 kV connections to Iran and Georgia will intrinsically change and strengthen the system. It will also subject the system to a natural load flow loop of Russia to Ukraine to Romania to Bulgaria to Turkey to Georgia to Russia that can involve up to 300 MW which could create problems in the South Caucasus region.[24] System designers will take this issue into account as the additions are made to the system.

4.1.2 Frequency and voltage stability

After the collapse of the Soviet Union, Armenia experienced power shortages and the country was required to restrict the use of electricity to one hour per day for many users.

[18] Meeting with the Network design Institute, April 9, 2008
[19] Mode Calculations for Development Scheme of Armenian Power System, Scientific Research Institute, CJSC 2006 para. 4.2.2
[20] EIA Country Analysis Briefs, Caucasus Region, May 2006
[21] Ibid
[22] Energy View of BSEC Countries 2006 page 81
[23] Ibid
[24] Black Sea Region Transmission Planning Report, Executive Summary Regional Model Development and Network Analysis Report, January 2007

At times the frequency on the grid was only 42 hertz; clearly automatic fault protection was shut off to do this. Since then the country has restored the electrical system and brought the nuclear plant on line. This has resulted in a grid system that has maintained stability even when the ANPP has tripped off line.[25]

Data on the frequency and voltage stability of the power system are not recorded by the system operator. Records for the ANPP substation indicate that there have been six occurrences over the past two years in which voltage dropped by more than five percent of nominal value for periods of up to two seconds. These voltage dips were said to be caused by short circuit conditions. There were no recorded events of frequency disturbances.

Analyses of the system load flow and stability are in a report by Network Design Institute (NDI) on the Armenia power system.[26] These analyses considered:

- One transmission line off service.
- Loss of large customers
- Loss of a single large generator, and
- Loss of export capacity

This study analyzed the system at 5 year intervals under specific assumptions on load growth and generation capability. Assumptions include a new 1000 MW nuclear unit replacing the ANPP by 2020, with export of over 1000 MW to Iran. The study included surveys of major consumers to identify planned load additions to specific system nodes. The study provided recommendations for system enhancements to assure reliability and stability under steady and transient conditions. NDI plans to update the study in 2009.

It should be noted that for scenarios involving the new 1000 MW nuclear unit, the study assumed that it had two 500 MW turbine generators and that only one generator would trip to induce a transient. In this scenario, the system was stable with some load shedding. This is not a realistic scenario for a nuclear unit, where a reactor trip will cause all generation from the unit to be lost.

Additional steady state and transient calculations for a 1000 MWe nuclear unit were performed by PA Consulting. These calculations are shown in Appendix A to this section. These calculations concluded that, with the addition of a high voltage transmission line from ANPP to Hrazdan substation, the stability of the system would be maintained during anticipated steady state and transient situations.

4.1.3 Spinning reserve capability

In an electrical grid, spinning reserve is the unloaded generation capacity which is synchronized and ready to serve additional demand. Adequate spinning reserve margins provide the grid with a cushion to respond to a sudden loss in generation. In a developed system, the available spinning reserve is equal to the output of the largest operating plant; typically in these systems, the spinning reserve is less than 10% of actual system load.

Armenia makes extensive use of automatic load shedding based on system frequency and the rate of change in frequency. In this way, the Armenian system relies mostly on

[25] Interview with Gurgen Hakobyan February 19, 2008
[26] Network Design Institute, Transmission Study Chapters 5-9

load shedding rather than spinning reserve to maintain the grid during large transients.[27]. With the schemes for automatic load shedding on the rate of change of frequency, the system operating rules require that the largest generator can be no more than 75% of the total system load. Also in place are interruptible contracts so that some loads would be shed as a matter of course if the new ANPP were to trip off line.[28]

While this works for the present system, it may need to be adjusted for a new NPP. For example in the VVER-1000, the reactor power reducing and limiting device (ROM) activates when the main circulation pump electrical frequency is less than 49 Hz.[29] If the grid frequency drops below this point prior to load shedding, the NPP may trip before any load is shed. This scheme should be reanalyzed in conjunction with the new generating plant.

Armenia does have extensive hydroelectric resources that could and do provide some spinning reserve. However, in 2003 it was reported that none of the hydro plants were considered capable of accepting automatic generator capacity control (AGC) without substantial rehabilitation[30]. AGC is necessary for a plant to play the part of a unit providing spinning reserve. In 2003, Russia's Unified Energy Systems (UES) signed a contract for a 15 year license on the Sevan-Hrazdan cascade of hydro plants and the EU announced a tender to rehabilitate the Vorotan cascade of hydro plants. These rehabilitation actions should lead to improvements in the AGC available in the system.

In light of the low load conditions that may exist at various times, particularly during the summer season, the new plant should have load following capability. Different plant designs have different capability in this regard. In earlier reactor types, a phenomena in the fuel, pellet clad interaction, reduced the ability of some plants to lower and raise power quickly enough to follow changes in load. New fuel designs have alleviated this concern somewhat. Natural uranium reactors have limited excess reactivity which can prevent them from overcoming the reactivity changes that occur due to fluctuations in xenon and samarium as power changes.

The conclusion of this section is that Armenia will not have the typical spinning reserve capacity to backup the new nuclear plant and will continue to rely on load shedding instead of spinning reserve. If the system upgrades and analyses that are planned are completed, the load shedding approach should provide sufficient protection from grid collapse on a trip of the proposed plant.

4.1.4 Tie line capacities sufficient to permit the secure transmission of power under all possible load flow conditions

In 2006 the Energy Scientific Research Institute, CJSC, prepared a report "Mode Calculations for Development Scheme of Armenian Power System". These calculations showed that the present system under steady state conditions is well developed and has extensive capacity. For the future, under steady state conditions the grid should be capable of transmitting needed energy within the domestic and regional market provided

[27] Gurgen Hakobyan Meeting March 26
[28] Meeting Gurgen Hakobyan February 19, 2008

[29] WWER-1000 Reactor Simulator *Material for Training Courses and Workshops* Second Edition, INTERNATIONAL ATOMIC ENERGY AGENCY, VIENNA, 2005, page 22, 23
[30] Political Conditions and Economic Opportunities for Regional Power Systems Cooperation, Strategic Research Institute, Friedrich Ebert Stiftung, 2004 page 16

the recommendations of the report are implemented.[31] The new 400 kV double circuit overhead lines to Iran will increase capacity to1000 MW. The 400kV transmission line between Armenia and Georgia will increase capacity to 600 MW. While these additions should strengthen the transmission system, they will likely require some design changes to ensure that the tie line capacities are sufficient under all possible load conditions; a study for this purpose is being planned for 2009. Necessary adjustments to the system will be made following the completion of the study.[32]

4.1.5 Measures for automatic load shedding based on frequency drop and time for fault isolation

Also reviewed was the ability of the transmission system to withstand transient or upset conditions. During transient conditions it is important to be able to quickly isolate the fault. Provisions to do so have been incorporated in the existing system.[33]

Today 80% of the system has automatic means to isolate faults. This is done in three ways:

- Sudden fault protection to isolate the fault in 0.02 seconds
- Under frequency protection to shed load at 48.5 hertz
- Protection on high rate of change of the frequency (this was added as a result of studies done by PA)[34]

4.1.6 Measures for management of reactive power in the grid

Analyses have been done[35] to study the distribution of reactive power throughout the grid. For the existing system the distribution of reactive power appears adequate. However, conclusion 6 of the report is that additional studies be done on the compensation of reactive capacities and voltage levels along the proposed 400 kV Iran-Armenia double circuit overhead line and that a 440 MVA inductive reactor be connected to the 400 kV system at Hrazdan-5 TPP substation. Discussion with the system designer[36] indicates that these steps are being taken as part of the installation of the 400 KV transmission lines. It was further indicated that additional studies would be done as additions are made to the transmission system. Necessary changes will be made to address the management of reactive power on the grid. The next study is planned for 2009.

4.1.7 System-wide co-ordination of protective relaying schemes

System-wide co-ordination of protective relaying schemes exists within the present system. Currently, there is a project underway for design and implementation of an automated Supervisory Control and Data Acquisition System (SCADA). Implementation of SCADA system will allow the system to respond more quickly in emergency cases and carry out switching by the central dispatching office. In the first phase the SCADA upgrade will be installed at the generating plants and the 220 KV substations. The second phase

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[31] Mode calculations for Development Scheme of Armenian Power System, Scientific Research Institute, CJSC 2006

[32] Meeting with EnergyNetworkDesign Institute CJSC, April 9, 2008

[33] Mode Calculations for the Development Scheme of the Armenian Power System, Scientific Research Institute, CJSC 2006

[34] Meeting Gurgen Hakobyan February 19, 2008

[35] Mode Calculations for the Development Scheme of the Armenian Power System, Scientific Research Institute, CJSC 2006

[36] Meeting with EnergyNetworkDesign Institute CJSC, April 2008

will address the 110 KV substations. SCADA will provide the system with state of the art automatic protection.

4.1.8 Measures for efficient communication between generating stations and load dispatch centers

Some measures are in place today to support the operation of the existing unit. Work has been done to improve the dispatch communications telemetry system. This should be further enhanced as part of the new SCADA system.

4.1.9 Clear strategies for operating the system during normal and contingency conditions

These strategies are already in place today to support the operation of the existing unit. The Electric Grid Code of the Armenian Power Sector provides extensive guidance in this area.[37]

4.1.10 Maximum allowable power transfer through a single interconnection

Analyses have been done[38] to study the distribution of power through all nodes of the grid. In general, these studies have shown a relatively high degree of redundancy as far as power transfer is concerned. The reference recommends specific design attributes for the 400 kV Iran-Armenia transmission lines and increases in conductor sizes for two 110 kV transmission lines. These changes should be addressed as part of the follow-up to the transmission line study; independent of the addition of a new plant.

4.1.11 Conclusions and Recommendations

In summary, the Armenian electrical grid is a relatively small system, relying primarily on load shedding to maintain system stability during transient situations. Connections with neighboring countries are being upgraded to provide greater capacity for power interchange.

These additional analyses should be employed:

- Periodic reanalysis of the grid and its transient stability should be done as the grid evolves
- Reanalysis of the load shedding scheme in light of the design of the new NPP facility to ensure they are compatible

These transmission system improvements should be made:

- Confirmation that AGC in the hydro plants is adequate
- The 400 Kv high voltage transmission line connecting ANPP with Hrazdan 5 substation should be constructed.
- Plans to safely and expeditiously restore offsite power to the reactor following a trip caused by a loss of grid. Typically this would be done by restarting another plant, perhaps a hydro plant, which would reenergize a portion of the grid. With the grid reenergized, offsite power to the nuclear plant could be restored.

[37] Electric Grid Code of the Armenian Power Sector (draft) prepared under USAID contract No. LAG-I-00-98-00005-00, Hagler Bailly Services, 1999
[38] Mode Calculations for the Development Scheme of the Armenian Power System, Scientific Research Institute, CJSC 2006

These features should be incorporated into the new plant:

- Additional redundancy in on-site sources of electrical power (diesel generators or gas turbines).
- Significant turbine bypass capacity, so the plant can accommodate large load rejections.
- Significant load follow capability
- Reactor and turbine generator control systems that are responsive to sudden and deep load changes
- Design of both the primary and secondary plant that allows the plant and a small load base around the plant to operate as an isolated “islanded” grid

If existing plans are followed and the recommendations above implemented, the Armenian transmission system should be capable of supporting a new nuclear unit. The transmission network development plan assumes finishing the 400 kV transmission lines prior to commissioning of a new Armenian NPP. The total designed capacity of these lines (2240 MW) would provide a power system with the necessary capacity to export all electricity produced in excess of the domestic demand.

Features of the new plant which would make it more resilient to grid fluctuations are large turbine bypass capacity and responsive control systems for reactor power and turbine generator load. The large turbine bypass capacity allows steam to be dumped to condenser rather than flowing to the turbine and the responsive control systems allow reactor power and generator output to rapidly adjust to the changing system load. Without these features, imbalances (which are more frequent in a weak grid) between reactor power, turbine generator output and system load will cause the turbine generator and the reactor to trip.

4.2 TRANSPORTATION

This section will evaluate transportation routes that could be used to bring plant equipment and construction materials to the ANPP site. Constructing an NPP involves transporting many large and heavy pieces of equipment. Table 4-1 provides examples of the major equipments for each of the candidate plant designs.

Table 4-1, Major NPP Equipment to be Transported

Component	Size (meters)	Weight (metric tons)
Westinghouse AP 1000		
Reactor vessel	6.7 (D) x 10.4 (L)	500
Steam generator -1	6.1 (D) x 24.4 (L)	630
Steam generator -2	4.9 (D) x 24 (L)	630
1120 MWe Turbine-generator		
Turbine rotor	5.5 (D) x 8.8 (L)	230
Turbine stator	5.5 (D) x 12.2 (L)	454
Moisture Separator-Reheater	4.0 (D) x 31 (L)	400
CANDU EC 6		
Equipment Airlock	7.5 dia. X 12.5 L	110.0
Steam Generator	4.3 (2.9) Dia. x 20 L.	200.0
Standby Diesel Generators	7 x 5 x 5 H	150.0
Turbine Generator Rotor	15 x 4 x 4 H	150.0
Turbine Generator Stator	12 x 6 x 6 H	320.0
Main Output Transformer	8 x 5 x 8	150.0
Condenser Modules	15 x 5 x 5	200.0
Calandria	8.53 W. x 8.96 H. 8.48 L.	250.0
Moisture Separator Reheater	25 x 5 x 5	350.0
VVER 1000 AES 92		
Reactor vessel		
Steam generator -1		
Moisture Separator-Reheater		
Moisture Separator-Reheater		
Standby Diesel Generators		
Turbine Generator Rotor		
Turbine Generator Stator		
Main Output Transformer		

Due to geopolitical issues, the borders of Armenia with Turkey and Azerbaijan are currently closed. The closure of borders by Azerbaijan was specifically damaging for Armenia, since it was the route for transportation to Armenia of large, heavy goods and equipment from Russia. Currently, the only route for heavy loads connecting Armenia with the rest of the world goes through Georgia (railroad and motor roads) and two Georgian ports: Poti and Batumi.

4.2.1 Ports

Out of two main ports in Georgia, Poti is the larger one with higher capacity for cargo processing and transportation. Currently the volume of cargo processed by the port of Poti is much larger than it for the port of Batumi. However, as discussed in sections 4.2.2 and 4.2.3 below, the specifics of transportation routes from the port of Poti exclude it from consideration for transportation of large and heavy loads for Armenian nuclear unit.

The only option which remains is the port Batumi, which is connected with Armenia through the motor road without tunnels and major bridges. The current weight lifting capacity of the port is quite limited (up to 180 tones) and port facilities will have to be upgraded substantially to handle the large nuclear plant components. The port of Batumi is privatized and is owned by the Kazakh Company.

4.2.2 Railway Transportation

There is a rail road line from Poti in Georgia, through Tiblisi and into Armenia. However, this railroad is not really an option for transportation of large and heavy goods for two reasons:

- The major part of the railroad connecting Georgia with Armenia was built at the end of 19th and the beginning of 20th century by the Russian Empire. The railroad follows the river Debet canyon and passes numerous bridges, which are more then 100 years old and were not designed for very heavy loads.
- The railroad passes many tunnels with quite small diameters, which limits transportation of large goods.

Although not suitable for large and heavy loads, the railroad can be used for transport of smaller equipment and commodities for construction of the NPP.

4.2.3 Highways

The roadways connecting the port of Poti with Armenia are not suitable for transportation of large equipment and heavy loads. The roadway connecting Poti to Tbilisi and then down to Armenia has the same deficiencies as a rail road discussed above. The same is true for the road from Poti to Batumi. The road goes through very mountainous terrain with sharp corners. In order to improve the road, the Government of Georgia financed construction of two tunnels, one of which is completed and the second one is under construction.

The port of Batumi is connected with Armenia by a roadway without tunnels and major bridges. The motor road from Batumi to the ANPP goes through the following cities:

- Batumi
- Akhaltsikhe
- Akhalkalaki
- Ninotsminda
- Ashotsk
- Gumri
- Talin
- Ashtarak
- Vagharshapat
- Metsamor

The length of the road is about 450 km. The quality of the roadway in Georgia is not very good and the road was not maintained properly for a long time. However, the Government of Georgian has initiated the overhaul of the road. The Akhaltsikhe-Akhalkalaki section of the road has been repaired with concrete and then asphalt pavement. There are plans to repair the section Akhalkalaki-Ninotsminda as well. The road goes through mountain passes with narrow lacets. There are several sections where the road is very steep. It will probably be necessary to widen the road in several places in order to move large and heavy loads.

The Armenian part of the road is in better condition, without any very steep sections. However, there are several small bridges crossing small rivers and ravines, which may have to be strengthened.

Large NPP components can be moved by road using special transport trailers. The transport of the calandria for the CANDU reactor at Qinshan China is illustrated in figure 4-1. These multi-axle transporters can handle loads up to 700 tons. However, speeds are limited to less than 20 km per hour on level ground. Transport of large and heavy loads will require closing the road to other traffic. Such closures could be done during the night while the heavy load is being moved and during the day the road could be reopened while the heavy load is parked. Additionally power lines would need to be moved, temporary bridges employed and other obstructions identified and relocated. The entire route should be carefully surveyed to determine the improvements needed for transport of large and heavy loads.

Figure 4-1, Transportation of the Calandria for CANDU 6 Reactor in Qinshan China

4.2.4 Transportation of Bulk Materials

Transportation of construction materials such as cement would mostly be by railroads. There are two railroads from the two large cement factories to Metsamor: 60 km from Ararat, and 100km from Hrazdan. Another option for providing concrete for construction of NPP according to Ministry of Transportation is the establishment of concrete production factory near the NPP construction site.[39]

4.2.5 Transportation of Construction Modules

Several of the potential plant suppliers use modular construction techniques to increase construction efficiency and shorten schedules. In general, these modules can be shipped as entire units or shipped to the site in smaller subunits that are then assembled on site. Typically these modules are quite heavy; up to 950 US tons. For the most heavily modularized design, it is expected that about 350 modules would be required.[40]

The four types of modules planned and the approximate number required are:

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[39] Meeting with K. Kababyan, Deputy Head of the Development Programs and Investments Department - Head of Investments Division of the RoA Ministry of Transport and Communication. 27 June 2007

[40] DOE NP2010 Construction Schedule Evaluation, Prepared for the U.S. Department of Energy, under contract DE-AT01-020NE23476, MPR-2627 Revision 2 September 24, 2004

• Mechanical Modules (140/unit) – mechanical equipment on a common structural frame along with interconnecting piping, valves, instruments, wiring, etc. Mechanical equipment modules contain equipment such as heat exchangers, pumps, and vessels on a common structural frame. The equipment will be supplied along with associated piping, valves, instruments, wiring, conduit, cable-tray and other such ancillary items.

• Structural Modules (60/unit) – liner, wall, floor, heat sink floor, turbine pedestal form, stair, platform, structural steel and space frame modules. Some structural modules would include leave-in-place formwork for concrete. Structural modules are used to speed concrete and structural steel installations. These modules are constructed of steel plate that can serve as leave-in-place concrete forms and structural steel. The steel plate will be reinforced as needed to contain and reinforce the concrete poured into these modules on-site. Internal bracing between steel plates is provided as required to allow for transportation and setting the structural modules in place. These modules may be outfitted with pipe, duct, and cable tray.

• Piping Modules (130/unit) – pipe, valves, and associated instrumentation and wiring on a common structural frame. Piping modules contain pipe and valve assemblies and their ancillary instrumentation. These modules may also contain sections of electrical raceway and HVAC ducts. Piping modules may contain several pipe runs and their supports mounted on a surrounding structure.

• Electrical Modules (20/unit) – electrical equipment on a common structural frame. The electrical equipment modules for GEN III+ units would include prefabricated power distribution centers and indoor substations. The modules will be constructed on skids. As self-contained units, these modules can be completely coordinated, assembled, and tested in a controlled factory environment. If integral transformers are close-coupled to switchgear or with bus duct connections, these modules can serve as a complete unit substation.

For a site in Armenia with no seaport and limited transportation routes, shipping certain of the completed modules is out of the question. Both the weight and the size are beyond the capability of existing transportation into the country. For those modules that are too large, sub-modules could be completed at the factory and shipped separately to the site with final module assembly in an on-site facility. Or components can be fabricated in a factory, with modules entirely fabricated in an on-site facility.

If the material is shipped as subunits, one source[41] has estimated that the subunits for truck transport could have dimensions of (3.66 m x 3.66 m x 12.2 m) and weigh 40 tons, and modules for rail transport could have dimensions of (3.66 m x 3.66 m x 24.4 m).

When sub-modules are completed in a factory, shipped separately to the site, and final module assembly is in on-site facility; a workshop or even a comprehensive facility is needed for on-site assembly of modules. At some nuclear power construction sites large facilities have been built which include several workshops for mechanical, electrical and electronic works, non-destructive examination and for module fabrication and assembly.

[41] Study of Construction Technologies and Schedules, O&M Staffing and Cost, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs, United States Department of Energy Cooperative Agreement DE-FC07-03ID14492 Contract DE-AT01-020NE23476, Dominion Energy Inc. , Bechtel Power Corporation, TLG, Inc., MPR Associates May 27, 2004

For example, at Kashiwazaki-Kariwa about 10 000 square meters of workshops were used by Hitachi.[42]

The transportation methods available to the construction site will affect the module types used in the plant construction. As it becomes necessary to divide the modules into a greater number of smaller subunits, plant cost will rise and construction schedule will stretch longer.

As noted, the completed modules are of impressive size and require a “Very Heavy Lift” crane to move them about the construction site. These Very Heavy Lift (VHL) cranes are needed to support “open top” construction of GEN III+ units. GEN III+ plant construction requires a VHL crane with the capacity to lift and place up to 1,200 ton modules and components at a 130-foot radius and a height of 200-feet. GEN III+ plants require a main boom capacity of up to 1,500 tons and an auxiliary boom capacity of up to 250 tons. In some instances, plant construction requires the VHL cranes to pick up and travel with large modules. One of these cranes would be required for transportation of modules at the construction site.

4.2.6 Conclusions and Recommendations Regarding Transportation

Transportation of materials to the site can be performed by; rail, highway or air. However, for transportation of large and heavy equipment, road transport through the port of Batumi in Georgia is the only feasible option. To prepare for construction of the new ANPP unit, the following actions are recommended:

- Perform a comprehensive survey of the roadway from Batumi to Metzamor to determine the technical characteristics and determine the improvements that will be needed.
- Perform a survey of the port facilities at Batumi to determine the existing capabilities and identify needed improvements
- Establish an agreement with the Government of Georgia for use of the roadway for NPP shipments, including provisions for road improvements and repairs as well as road closures during shipments.

4.3 COOLING WATER

The objective of this section is to determine the feasibility of supplying sufficient cooling water to the new nuclear unit. Because of its larger size, the new nuclear unit will require substantially more cooling water than the existing ANPP if conventional natural draft cooling towers are used. Based on the data from the NEI plant parameter envelope, the new unit normally would require about 2,000 liters per second (l/s) and have a maximum usage of 2,700 l/s. This water is used primarily for makeup and blow down of the circulating water system.

4.3.1 Existing ANPP cooling system

The existing ANPP, uses a natural draft wet cooling tower design. Unit 1 also had a wet tower system; and a wet tower system was planned for units 3 and 4. The source of make up water to replenish evaporation and drift losses by ANPP is the Sevjur River, which is a left tributary of the Araks River. The Sevjur River is 38 km long. The river is spring-fed.

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[42] IAEA-TECDOC-1390, Construction and commissioning experience of evolutionary water cooled nuclear power plants, April 2004

There is a pumping station on this river 13 km away from the ANPP. The pump station has 5 pumps with 3000 ton/hr capacity each and only one is needed to supply ANPP unit 2. There are two pipelines from the pump station to the plant. The land for the pipelines is owned by ANPP. Cooling water from the pipelines enters on site channels, which hold 100,000 tons of water. Water from the channels is used as circulating water for the condensers, is cooled in the cooling towers, and then returns to the onsite channels. As a result of evaporation process in the cooling towers, the cooling water mineral content increases. These channels are flushed with fresh water to reduce mineral concentration.

A collection pond fed by ground water, was created as a second source in the late 1980's in anticipation of the construction of Units 3 and 4. This pond was sized for servicing the units, but is in need of silt removal if it is to be used to supply the full needs of the ANPP.[43] Both the Sevjur River and the collection pond are fed by groundwater that ultimately comes from the same aquifer. There is a pumping station with 4 pumps at the pond. The capacity of the pumps is 3000t/hr each. One pump is enough for operation of the unit 2.

Permits for use of water resources in Armenia are managed by the Water Resource Management Agency under the regulation of the National Water code and related regulations. The current ANPP has 2 water permits, one for the groundwater collection pond of 170 liters per second (L/sec) and one for the Sevjur Pumping Station for 998 L/sec. Because of seasonal low flows in the Sevjur, they have been authorized by letter to take additional water from the collection pond while reducing the take from the Sevjur. ANPP permits were first issued in 2004, renewed in 2007, and probably will be renewed in 2010 for a period of 25 years.

4.3.2 The Sevjur River and Collection Pond

The first option for cooling water for the new unit is to pump water from the Sevjur River and collection pond in the same way as is done for the existing ANPP. Although the existing pumping stations and pipelines have sufficient capacity to meet the water requirements of the new unit, they would probably need to be refurbished to ensure reliability during the 60 year life of the plant. The existing pond should be dredged and rehabilitated and new, pumps, piping and controls should be provided.

However, increasing the withdrawal of water from the Sevjur River will require equivalent reductions in the amount of water available for other users. In addition to the ANPP, other users of the water from the Sevjur River are pipelines that provide irrigation water for agriculture and fisheries that use water for fish ponds. Eleven irrigation pipelines are permitted to take 6,300 L/sec and 130 fisheries are permitted to take 11,100 L/sec. The total permitted withdrawals from the river are 18,800 L/sec, which is the entire available capacity of the river. If the nuclear plant is permitted an additional 1,000 L/sec, the other users will have to take a six percent reduction.

In a letter from the Minister of Nature Protection to the MoENR (November 15 2007), it was indicated that the Sevjur River could be used as the source of technical water for the new unit at the site of the existing ANPP but the location and amount of extraction should be determined through the water permit process. Discussions with the Water Resource Management Agency have indicated that the reduction in the permitted water use by fisheries or agriculture would not be approved without sufficient compensation for those users. The compensation could be used to obtain alternative water supplies for those

[43] Meeting with, Movses Vardanyan (ANPP Chief Engineer), Leonti Chaloyan, Varazdat Mkrtchyan, Mr. Samuelyan, August 8, 2007

users from further downstream in the Sevjur River or from another source. Alternatively, sprinkler type irrigation systems could be installed to reduce the amount of water needed for irrigation. Considering the location and high reliability requirements of the NPP, it would certainly be more efficient to arrange an alternate source for a small portion of the irrigation water than to relocate the pumping station and extend the pipelines for the new unit cooling system.

4.3.3 Dry and Hybrid Cooling Towers

A second option is to construct the new unit to use a hybrid cooling tower or a combination hybrid and dry cooling tower. Conventional wet cooling towers involve evaporating a significant amount of water to reject the heat from the power cycle. Dry cooling systems reject the heat of condensation directly to the atmosphere. Steam from the turbine exhaust is ducted to an air cooled condenser. The condenser consists of a modular arrangement of cells, each in the general shape of an A-frame structure. The sloping sides are arrays of finned tube bundles. An axial flow fan, in the floor of the cell draws air from the environment below the cell and forces it up and out across the finned tubes. The steam flows into the finned tubes where it condenses and drains down to a condensate line at the bottom of each side of the cell. The condensate is then returned to the feed water loop.

Hybrid cooling systems are intended to exploit the virtues of both the wet and dry systems while reducing the drawbacks of each. In these systems, both air-cooled and wet cooling equipment are available for handling the plant heat load as conditions dictate. Hybrid cooling systems reduce the amount of water required for power plant cooling by using dry cooling during periods of low water availability and wet cooling when there is sufficient water available. This hybrid type cooling system is planned for the new nuclear units at the North Anna NPP in the US.

Capital cost, land area required, and operational cost (higher plant auxiliary electrical load) of the cooling system are negatively affected by increasing the percentage of dry cooling in the cooling system. Additionally, the high condenser return water temperatures inherent in the inefficiency of the dry cooling process under high ambient air conditions significantly affects the plant’s thermal efficiency, resulting in fewer megawatts of power generated. The higher backpressure may also require significant alterations to the turbine design to prevent water entrainment and erosion. The combination of higher plant auxiliary load and decreased thermal plant efficiency not only results in lower net electrical power generated by the plant, but at very high percentages of dry cooling during summer operation, the plant may need to further reduce output to maintain an acceptable condenser backpressure.

The North Anna NPP has estimated that, in comparison to wet cooling towers, dry cooling towers have an energy penalty of 6.6 to 9.5 percent.[44] Assuming a 1000 MW plant with a capacity factor of 90% the penalty could reach $20 million dollars per year when comparing a plant with a dry cooling tower to one with a wet cooling tower. The operating cost penalty decreases to zero in a linear fashion as the percentage of dry cooling decreases. In the case of Armenia, the hybrid cooling system could operate in wet mode for most of the year, switching to a wet/dry mode when water is needed for irrigation.

[44] North Anna, Early Site Permit Application to the USNRC, Part 3 - Environmental Report, July 2005

The capital cost for installation of dry cooling for a 1000 MW plant is about $70 million higher than wet towers.[45] The difference in capital cost between wet and dry cooling decreases in a linear fashion as the percentage of dry cooling decreases.

4.3.4 Other Water Sources

Another option for increasing the water available to ANPP is to obtain water from another source. Recently there have been major improvements made to the dam and intakes on the Araks for the Armavir Canal, which can deliver water from the Araks River over to the Sevjur River. Another potential source would be the Kasakh River, which enters the Sevjur about 5 km downstream from the ANPP water intake. There has been a feasibility study to build a pipeline from the Shirak region mountains to the Metsamor region. Such a pipeline could be used to increase the available water supply.

It is also possible to develop additional wells to tap underground water. There are many wells in the region that are no longer used and create problems with too much water coming to the surface. Considering the location and high reliability requirements of the NPP, it would probably be more efficient to develop these alternate sources to supplement the water available for irrigation or fisheries rather than reconfiguring the NPP cooling system.

4.3.5 Conclusions and Recommendations

It is concluded that there is a sufficient capacity of water in the Sevjur River and collection pond to provide for the water needs of the new nuclear unit in the same way as is done for the existing ANPP. However, increasing the water permit for the nuclear plant will require a small reduction in water available to other users. The reductions to other users could be compensated by water taken further downstream the Sevjur, or from other water sources in the region.

The determination of water allocations in Armenia is done through the water permit process administered by the Water Resource Management Agency. It is recommended that the MoENR initiate application for a water permit for the new unit as soon as possible, in order to have the permits in place when the bid specifications are issued. The data from the Plant Parameter Envelope should provide a sufficient technical basis for the permit request.

If the permit process does not approve an increase in the water allocation for the ANPP, the specifications for the new unit will have to include a hybrid cooling system, similar to that designed for the North Anna NPP.

4.4 INDUSTRIAL SUPPORT

This section identifies and evaluates capabilities for in-country support for construction materials and services. Databases of domestic manufacturers and support organizations have been reviewed to determine adequate suppliers. Also reviewed was the feasibility of in-country manufacture of proprietary components through technology transfer and license arrangements from the original equipment manufacturer.

The availability of skilled craft for NPP construction as well as programs for training and qualification of the crafts are addressed in section 9 of this document.

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[45] F. Faysal and M. Moe, SAIC, Symposium on Cooling Water Technologies to Protect Aquatic Organisms, May 6, 2003

Presently our research has identified few domestic possibilities for technology transfer. The manufacturing base appears simply too weak to assume the job of manufacturing sensitive proprietary components for the proposed plant. Areas that may be amenable to the present industrial base in Armenia are: supply of bulk materials; supply and construction of offices, warehouses and shops; plant doors, supply of heating, and ventilating and air conditioning equipment (HVAC). These would require adjustment to the current products now being produced.

4.4.1 Construction Materials

DOE estimates that the following amounts of bulk materials are needed for the construction of a new single unit:[46]

• Concrete – 460,000 cubic yards (not including concrete for site preparation) (about 1 million tons)
• Reinforcing Steel and Embedded Parts – 46,000 tons.
• Structural Steel, Miscellaneous Steel, and Decking – 25,000 tons.
• Large Bore Pipe (> 2½ inch) – 260,000 feet (80 km).
• Small Bore Pipe – 430,000 feet (130 km).
• Cable Tray – 220,000 feet (67 km).

There are two major cement producers in Armenia: Mika-Cement CJSC and Ararat Cement Factory. The Mika Cement CJSC plant is located in Hrazdan city and specializes in production of Portland cement. Its production is used locally as well as exported to Georgia and Azerbaijan. The Mika-Cement cement production capacity is currently about 300,000 tons per year. Commissioning of a second production line will be required to boost up its production to 800,000 tons per year. The second company, the Ararat Cement factory, began cement production with a new dry method in 1989 with 120.000 ton designed annual production capacity. The domestic supply of cement in Armenia appears to meet the needs of the plant. This material has been used to construct the Independent Spent Fuel Storage Facility at the ANPP and the quality was good. Sand and aggregate of sufficient quality are also available in abundance in Armenia.

Several Armenian manufacturers of construction materials were identified. The Mikmetal Company manufactures reinforcing bars (rebar) and imports other structural steel products for the Armenia market. Mikmetal production facilities are certified to ISO 9001-2000. The Hanny-Armin company of Yerevan produces electrical power and control cables, transformers, and other electrical equipment. There are also a number of manufacturers of materials such as plastic pipe, ventilation ducts, metal doors, and storage racks used in commercial construction. No pipe manufactures have been identified.

4.4.2 Equipment Manufacturers

Armenian industry may be able to find a niche in the production of some of the equipment needed at the new nuclear unit. The Armenian precision engineering sector was one of the most technologically advanced sectors of the economy during Soviet times. The sector manufactured equipment for production processes throughout the Soviet Union. Both

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[46] DOE NP2010 Nuclear Power Plant Construction Infrastructure Assessment Prepared for Department of Energy, Washington, D.C. Under Order No. DE-AT01-020NE23476, MPR-2776, Revision 0, October 21, 2005 p. 3-9

production and employment peaked in the mid 1980s. As of 2003 there were 32 precision machinery enterprises registered with the government. However, some do not operate, and others do so at much reduced capacity.

Armenia does export some precision equipment. Some of the exports are used or warehoused equipment and do not necessarily represent new production.[47] Domestic production now supports private and commercial construction and produces things like; doors, doorframes, ventilation equipment, paints, and similar items. All of these would be heavily used in plant construction and it is feasible that the existing processes be adjusted to allow production of similar products for the nuclear plant.

A review of listings of manufacturers and their products in Armenia indicates the following products that may have application at the plant:[48]

- Electrical cable, ignition cable
- Motors, transformers
- Electric drives
- Bus bars
- Welding units
- Metal structures
- Drilling machines
- Galvanized steel
- Heat ventilation and air conditioning equipment (HVAC)
- Boilers
- Construction buildings
- Foundries, castings
- Cast iron sewer pipes, plastic pipes
- Thermostats
- Paint

4.4.3 Conclusions

Without question concrete and its constituents can be supplied domestically. There are no domestic suppliers of safety related plant equipment and considering the difficulty of rebuilding a shop and qualifying the supplier it is not recommended that safety related equipment be supplied from internal sources. With the exception of rebar and cables, bulk materials are not presently available from within Armenia. However, with some investment, existing manufactures could begin to produce some of these components. Companies in these industries should be given the opportunity to bid. The most likely industrial products that could be produced are:

- Cable tray
- HVAC duct and equipment
- Decking
- Metal structures and construction and office buildings
- Galvanized steel
- Paint

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[47] Armenia Competitiveness Assessment, USAID/Yerevan, Nathan Associates Inc., J.E. Austin Associates Inc, UNDER CONTRACT NO. PCE-I-837-98-00016-00, June 2004

[48] http://www.spyur.am/eng/z1bb.htm

4.5 SITE CONSTRUCTION CHARACTERISTICS

The proposed nuclear unit would be constructed immediately next to the existing ANPP and therefore would have a ready access to electricity from the 110 KV and 220 KV transmission systems. All that would be required is a tie to these systems. This has been confirmed by the management of the ANPP.[49]

The construction of the new unit would have a ready access to potable water sources of the ANPP. This has been confirmed by the management of the ANPP.[50] The present source is from the Upper Zieva Springs. It is expected that as construction proceeds, additional water needs will develop and the ANPP Unit 2 Safety Analysis Report [51] describes an aquifer, on site, whose chemical and bacteriological water composition fully meets the requirements for potable quality water. A successful test well has been drilled. Design for four production wells has been prepared and could be implemented if needed for construction of the proposed new unit.

The additional source described above is more than sufficient to supply the expected potable water needs for the proposed plant as indicated in the PPE[52] (16.3 l/s maximum), as well as the operational needs for the dematerialized water system (DWS) (32 l/s maximum) and the fire protection system (62 l/s maximum). Once this improved source of potable water is operational, the Upper Zieva Springs source may be available for construction purposes, such as concrete batch facility operation, dust suppression, and construction work force sanitary needs.

The ANPP site firefighting water supply currently draws from the household and drinking water supply system described above. The extensive length of the water supply pipelines from the Zieva Springs site, as well as the difference in the quality of the soils (rocky at the plant site, loose along the pipeline route below the plant site), create risks to this water supply, especially in the event of seismic events.[53] The commissioning of the new water supply consisting of deep wells and water intake from them into the firefighting water supply system will provide a more reliable source of water with volumetric capacity in excess of that indicated in the PPE (0.3 l/s monthly average, 62 l/s maximum)[54].

According to the construction company that built the Independent Spent Fuel Storage Installation of the present ANPP, sand and ballast in the quantity needed are easily available within Armenia.[55]

Construction of the new plant will involve excavation and removal of the excavated soil as well as demolition of a number of abandoned concrete buildings. Much of the area to be excavated was previously excavated for ANPP units 3 and 4 and then filled in when plans for these units were cancelled. There are approximately 20 abandoned concrete buildings on the site. While some of these may be rehabilitated for use as workshops or store rooms, most will probably need to be demolished. Locations for disposal of excavated material and debris from demolished buildings are available on the site, which is a

[49] Meeting with the ANPP management, January 31, 2008
[50] Meeting with the ANPP management, January 31, 2008
[51] Safety Analysis Report on Power Unit № 2 at the ANPP, Section 1.4.10
[52] Nuclear Energy Institute (NEI) Plant Parameters Envelope (PPE) Worksheet, Revision 0, February 2003
[53] Safety Analysis Report on Power Unit № 2 at the ANPP, Section 1.4.11
[54] Nuclear Energy Institute (NEI) Plant Parameters Envelope (PPE) Worksheet, Revision 0, February 2003
[55] Meeting notes, meeting with Ashot Vardanyan, Director HAEK-i SHINARARUTIUN CJSC on 8 April 2008

relatively barren area, owned by the government. The plant management has indicated that there is no chemical or radioactive contamination of soil at the construction site.[56]

Transportation of construction material is discussed in section 4.1 of this report. The local transportation routes are in place to support the plant. The location of the plant is near the auto route M-5 with a short distance to travel on the state (marz) route H-16. The rail line connecting Gyumri to Yerevan runs near the plant and a spur has been provided from this line to plant complex.

No public transportation routes are located within the site boundary. Existing and new roads will be used or constructed inside the ANPP site. Physical impacts due to site road construction will be limited to plant construction workers. The eastern plant access road may be upgraded to facilitate delivery of equipment, but since this will use an existing right-of-way passing through agricultural land, impacts are expected to be minimal.

A railroad spur enters the site on its western boundary, extends across the south half of the site, and ends near Units 1 and 2. Upgrading this existing rail spur and/or extension of a spur within the site boundaries into the construction support area may be necessary to support equipment delivery. No reconstruction of the rail line spur is expected outside the site boundary, but in the event such upgrading is necessary, since the rail line makes use of a pre-existing right-of-way, construction impacts are expected to be minimal.

In conclusion, the ANPP site is well suited to support construction of an additional unit with no unusual construction requirements. Transportation, water, space, and condition of the soils all provide easy adaptation for the construction of the new unit. While some upgrading of facilities will be required, the cost of these upgrades will be less than the cost associated with providing the same services at plant built on a green field site.

[56] Meeting with Leonti Chaloyan, Varazdat Mkrtchyan, Mr. Samvel Maghakyan January 31, 2008

APPENDIX A TO SECTION 4

HIGH VOLTAGE NETWORK ASSESSMENT

Technical Study Report

5. REVIEW OF OPTIONS FOR WASTE MANAGEMENT AND DISPOSAL OF SPENT FUEL

As a byproduct of their operation, nuclear power plants produce radioactive waste that must be stored and ultimately disposed of in a safe manner. In this discussion these materials will be divided into two categories:

- Low Level Wastes (LLW) are radioactive wastes that do not exceed 4 gigabecquerels per ton (GBq/te) alpha or 12 GBq/te beta/gamma activity. LLW are generated from NPP operations and decommissioning.

- High level waste (HLW) is primarily the waste from spent nuclear fuel as well as in-core materials. Sometimes, the spent nuclear fuel is reprocessed and the high level waste is the residual material left after useful fuel has been removed.

Options for management of these radioactive waste streams for the new nuclear unit are discussed in the following sections.

5.1 MANAGEMENT OF LOW LEVEL WASTE

Low and intermediate level radioactive waste is produced from nuclear plant operation and decommissioning. Most LLW from the operation of nuclear facilities is mainly paper, plastics, cloth, and scrap metal items as well as contaminated tools and discarded components. Typically, LLW are stored temporarily on the plant site in a radioactive waste storage building. Eventually the waste must be moved for final disposal to a disposal facility that will ensure that the waste is isolated for periods of 300 years or more. (1) The size of the new nuclear unit temporary storage building, the distance to the disposal facility, and the method of final disposal will have significant effects on the capital and operating cost of the new nuclear unit.

The major components of nuclear plant decommissioning LLW are soil, building rubble and steel items such as ducting, piping and reinforcement from the dismantling and demolition of contaminated systems and structures. Because of the large volumes involved, decommissioning waste is usually taken directly to the disposal facility rather than stored temporarily.

Management of LLW includes conditioning or treating the waste prior to disposal. Conditioning activities include:

- Liquid wastes are concentrated and solidified to prevent migration
- Dry waste are compacted or incinerated to reduce volume
- Wastes are packaged in high integrity steel or concrete containers with grout or asphalt to fill void spaces

After conditioning, waste can be transported for disposal or returned to temporary storage until disposal facilities become available.

The operation of the new nuclear unit will generate large volumes of LLW. The NEI Plant Parameter Envelope (PPE) (2) provides a bounding estimate for solid radioactive waste volumes of 55 m^3/year for the single unit AP1000 and 42 m^3/year for the ACR. However, the PPE is based on bounding values and should be considered as the high end of the range. In 2000, the average annual low level waste produced by NPPs was 35 m^3/unit, according to the World Association of Nuclear Operators (WANO) performance indicators. Assuming that the new nuclear unit will have state of the art waste compacting technology, the annual LLW generation should not be more than the industry average. Therefore, operation of the unit for 60 years would produce about 2,100 m^3 of LLW. Decommissioning will produce an additional 8,000 to 10,000 m^3 of waste.

Developing the strategy for management of LLW requires decisions on the methods and timing for final disposal as well as legal and financial arrangements for the disposal facilities.

5.1.1 Present Low Level Waste Situation in Armenia

All solid and liquid radioactive wastes that have been generated throughout the operational life of the ANPP are currently in interim storage on the plant site in various facilities. These wastes include LLW and some HLW. The volume of this waste at the time of permanent shutdown of the plant is projected to be about 12,600 m^3, the majority of which is solid low-level waste. (3) Decommissioning activities are projected to generate about 9,000 m^3 after processing.

Low level waste from the ANPP is being stored in a storage vault, which is located near the Unit 2 essential service water spray ponds. At present, the waste is stored there in a loose form (without compaction, incineration or packaging). The total volume of the storage vault is 17,051 m^3. As of 2007, approximately 5,300 m^3 of material was stored in the vault. (3)

Intermediate level waste (ILW) materials are currently stored in a special building adjacent to the plant. Little of ILW has been compacted, solidified, or packaged as necessary for disposal. This special building is full and the waste will soon be moved to waste storage buildings on the ANPP site that are owned and operated by the State Enterprise for Decommissioning of Radioactive Waste (RADON). When this transfer is completed, two of the three RADON buildings will be full. A third RADON building is reserved for storage of industrial and medical radioactive materials.

High-level waste is stored in room A-110 of the reactor building. The storage capacity is 78.34 m^3. (4)

A study conducted under an IAEA Tailored Collaboration Project in 2003(5) evaluated the potential radiological dose to the population over the next 300 years from LLW and ILW in the ANPP Waste Storage Vault. The analyses were based on the following assumptions:

- The volume and activity of waste was based on estimates of the existing inventory of LLW and ILW as well as additional waste from operation of ANPP through 2016. The study indicated that there may be scope for some decommissioning waste subject to characterization of its activity content.
- Existing waste in the vault were assumed to be removed, compacted, and packaged in drums with grout. After the drums are replaced in the vault, the void spaces are filled with grout to increase long term stability.
- While the waste is removed, the vault is inspected to confirm it meets original design specifications and is not deteriorated.
- After being filled with drums and grout, the vault is covered with material to minimize intrusion of rainwater and discourage future human intrusion.

The study results indicated the need for additional data on site and regional conditions of the site to confirm the validity of the generic data used in the calculations. The data necessary to confirm the analysis results include:

- More complete and detailed inventories of the radioactive and non-radioactive characteristics of current and future waste.

- Infiltration rates of rain water
- Sorption values for surrounding rocks
- Groundwater flow pattern
- Surveys of human, livestock, and agricultural resources in the vicinity

The study produced a draft report, which was never finalized. The draft report concluded that, subject to the assumptions and confirmation of the generic data, the dose to the population from feasible intrusion scenarios would be below Armenia's regulatory limits and international standards. This conclusion indicates it may be feasible to convert the vault to a disposal facility.

However, conversion of the existing waste storage vault to a final disposal facility will require considerable work to implement the assumptions of the analyses described above as well as completion of comprehensive Safety and Environmental Assessments. Even if the existing waste storage vault is found to be qualified as a disposal facility, it does not have sufficient volume to accept the decommissioning waste from ANPP in addition to the existing and future waste from ANPP operation.

A study conducted under the TACIS program in 2007[3] defines the decommissioning strategy for ANPP. The TACIS report has been adopted by RoA decree #48, November 2007. The TACIS report on decommissioning[57] recognizes that there is no low level waste disposal site in Armenia, and identifies the establishment of a disposal facility as one of the most critical items in the ANPP decommissioning strategy. The TACIS study assumes that the facility for final disposal of ANPP waste would be in service by 2037.

5.1.2 Alternatives for Low and Intermediate Radioactive Waste Disposal

Because Armenia does not have an existing radioactive waste disposal facility, there are several alternative approaches for the disposal of LLW from the new nuclear and decommissioning of the existing ANPP. The basic alternatives are:

- Transportation of the waste to another country for disposal
- Construct a waste disposal facility at the ANPP site
- Construct a waste disposal facility at another location in Armenia

Theses alternatives are discussed below.

Disposal of Waste in another Country

Low and intermediate level waste disposal facilities exist in a number of countries including France, Spain, the UK, Sweden, Finland, Germany, Czech Republic, Hungary, Romania, Russia, USA, and Japan. Current legislation in these countries prohibits the import of radioactive waste other than under very limited conditions. This situation may change in the future. For example, both Russia[6] and Kazakhstan[7] have been considering programs to allow import of radioactive waste for disposal. However, these proposals are strongly opposed by national and international environmental organizations. Under the program: Support Action: Pilot Initiative for European Regional Repositories (SAPIERR)[8], the EU is studying the feasibility of shared waste disposal facilities. However, this program would be limited to European nations.

If a foreign disposal facility becomes available, transportation of the waste to that facility would also be a problem. The transport of these wastes is commonplace and they are safely transported to waste treatment facilities and storage sites. Low-level wastes are moved by road, rail, and internationally, by sea. However, most low-level waste is only transported within the country where it is produced. Transportation through neighboring countries would require bilateral agreements and government fees for the shipment of radioactive waste. For example, shipment to Kazakhstan would require agreements with Georgia and Russia or Iran. The waste packaging and shipment technical characteristics would have to meet the regulatory requirements of each country transited as well as Armenia and the receiving country. Estimates for cost of transportation of LLW within a country are in the range of \$3,500 to \$5,500/m^3.[(9)] These transportation costs will be considerably higher for transportation through neighboring countries.

The fee charge by disposal facilities for LLW disposal varies over a wide range worldwide. For Europe it ranges from \$4,000 to \$13,000/m^3.[(3)] The lower figures come from countries of Central and Eastern Europe (e.g. Czech Republic) and the higher from West European countries (Germany, France). It should be expected that if a foreign disposal facility does become available for Armenian waste, the disposal fees would be at the upper end of this range.

Based on the above estimates of transportation costs and disposal fees, the total cost for disposal of 12,000 m^3 of LLW from the new nuclear unit in another country would be in the range of \$90-220 million.

Locating a New Low Level Waste Disposal Facility Elsewhere in Armenia

There are several disadvantages to establishing a new radioactive waste disposal facility elsewhere in Armenia rather than at the ANPP site. Licensing and environmental assessment of the facility at a Greenfield site would probably encounter strong public opposition and political resistance. Acquisition of the site, site preparation, construction of supporting infrastructure, and transportation lead to costs significantly higher than if the facility was located on the present site.

Although minimal, the main pathway to radiation exposure to the public during waste disposal is normally from the transportation of waste material to the disposal site. Transportation of the waste packages from ANPP to a remote location would create additional risk of public radiation exposure due to a transportation accident. For these reasons, establishing a disposal facility at a site other than ANPP should not be considered unless the ANPP site is found to be unsuitable from a safety assessment perspective.

Locating a New Low Level Waste Disposal Facility at the ANPP Site

A disposal facility on land at or adjacent to the ANPP site could make use of facilities and infrastructure of the site in managing and operating the facility as well as providing security. The costs and risks of transportation of waste packages to the disposal facility would be minimized if the facility is at the ANPP site.

There appears to be sufficient space available in the northern sector of the ANPP site for a near surface waste disposal facility. However, the suitability of this site must be confirmed through a comprehensive safety assessment performed in accordance with international guidelines[(10)] [(11)]. A facility with the capacity to dispose of the waste from the new unit operation and decommissioning as well as the operational and decommissioning waste from ANPP would have a total cost for construction and operation of between \$1,100 to \$1,500/m^3 of waste (see cost discussion in section 5.1.3).

5.1.3 Description of Low Level Waste Disposal Facility

Low- and intermediate-level waste packages are typically isolated in relatively near surface repositories in many states. The protective features include the waste packages, sealing materials in the repository, as well as the natural barriers to movement of material through the geological environment. Facilities for disposal of LLW need to provide high assurance of isolation for at least 300 years [11]. Several technologies exist for disposal of low level waste. These include:

- Landfill disposal- Landfill disposal is used only for very low level waste, often for activity levels that are below the established national limits for declaring the material radioactive waste. While this is an inexpensive option, it is not a safe or effective means of disposing of the wastes encountered at the plant.
- Near Surface disposal- Near Surface disposal is an option where radioactive waste is put in vaults. Essentially, short lived waste may be disposed of in such a facility. The activity of long lived isotopes is limited to low concentrations. Technology is available which is able to deal with large volumes such as waste from nuclear power plant operation and decommissioning.
- Trench disposal- Trench disposal is similar to a disposal in a near surface concrete vault but without insulation. Formerly, trenches were widely applied for disposal of all low level waste, but now they are considered inadequate.
- Subsurface disposal- Subsurface disposal relates to the disposal of wastes in rock cavities, bore holes or geologic structures. It is the most elaborate and expensive option.

The best technology for Armenia is near surface disposal in a vault. This type of structure provides the most cost effective assurance that waste will not migrate. An example of a near surface disposal facility for nuclear plant waste is shown in figure 5.1.

Figure 5.1: Püspökszilágy Disposal Facility in Hungary

The near surface disposal facility is essentially a concrete vault or series of vaults. The vaults can be constructed on the surface or in a trench. If above ground, the sides and top of the vault are covered with soil to provide shielding. Waste packages are brought to the facility in shielded containers on trucks or rail cars and loaded into the vault through access doors. In most modern facilities, the vault has a remotely operated overhead crane system to allow placement of waste packages in the vault without personnel entry. Vaults are also equipped with systems to monitor radiation internally and in ground water. After a vault is filled with waste packages, the void space in the vault is filled with sand or grout. As an alternative to filling, the waste packages can be placed in individual concrete canisters prior to being placed in the vault. After the vault is filled, it is closed by covering with a cap of clay, polyethylene liner, rock, soil, and vegetation designed to withstand long term environmental and weathering effects.

Operation of the waste disposal facility includes:

- Transportation of waste packages from the generator to the disposal site
- Receiving and inspecting waste packages
- Placing packages in concrete canisters (if applicable)
- Operating and maintaining the vault systems
- Security
- Filling and covering the vaults for closure

The disposal facility will be operated as long as waste is being generated by the new nuclear unit; through the end of the decommissioning period.

The 10 year period after the facility ceases to accept waste is designated the post closure period. During post closure, the earthen caps are completed, the site is graded and cleaned up, and monitoring of ground water continues.

The cost for construction, operation, and closure of a low level waste disposal depends on a number of factors, primarily the cost of materials and labor. The TACIS Decommissioning Strategy Report (3) provides a cost estimate of 42 MEUR for a disposal facility for ANPP waste. However, this estimate is based on European disposal fees rather than the cost of a facility in Armenia. The PNNL Decommissioning Cost Estimate for ANPP (4) provided an estimate (in year 2000 $) of $19 million to construct and operate the disposal facility for ANPP waste. The PNNL estimate was based on actual costs for similar facilities in the US, adjusted for Armenia labor costs. Escalating the PNNL estimate to year 2008 $ and adjusting for a smaller size, the cost of a disposal facility for 12,000 m^3 of LLW from the new nuclear unit would be in the range of $17 to $22 Million. Building a larger facility to dispose of LLW from the new unit as well as the existing ANPP would cost in the range of $33 to $45 million.

The timing of the opening of the waste disposal facility will also impact the cost of the new nuclear unit. Until the facility is opened, the new unit will have to store operational waste on site in a temporary storage building. If the LLW disposal facility is opened in 2037, as assumed in the TACIS Decommissioning Strategy Report (3), the new unit will need to construct temporary storage of 20 years of radioactive waste, about 700 m^3. Delays in opening the disposal facility beyond 2037 would require addition temporary storage capacity at a higher cost.

5.1.4 Radioactive Waste Disposal Facility Implementation.

The activities necessary for implementation of the radioactive waste disposal facility are discussed in this section.

Establish Legal Framework

It is necessary to establish government policies and legislation that define the overall national requirements and framework for the management of radioactive waste that will be generated during the nuclear plant operations and decommissioning. At the moment, there is no Armenian national policy or legal basis for responsibilities of disposal of radioactive waste.

Radioactive waste management activities are typically carried out by two different organizations, the owner/operator of the NPP in which the waste originates, and the owner/operator of the disposal facility. The owner/operator of the disposal facility would take the responsibility for siting, constructing, licensing, operating, and closure of the facility. In some cases, the operator of the facility may process wastes received, e.g., to package it. The national policy should establish the framework for ownership and operation of the disposal facility, clearly defining responsibilities of the organizations involved. The national policy should also establish the time frame for establishing the radioactive waste disposal facility.

Additionally, safety regulations related to radioactive waste storage, transport, packaging, and disposal must be developed by the Nuclear Safety Regulatory State Committee. These would include the regulations for licensing LLW disposal facility as well as the classifications of the waste and packaging requirements. These regulations conform to safety standards and guidelines provided by International Atomic Energy Agency (IAEA).

Financial Framework

Several different mechanisms have been used in other countries to finance the construction, operation and closure of radioactive waste disposal facilities. In some countries (e.g., USA, Germany, Spain), radioactive waste disposal facilities have charged waste generators a fee for each cubic meter of waste accepted for disposal. Additionally, disposal facilities may place handling surcharges based on the characteristics of the waste. If applied in Armenia, this approach would require the GoA to finance the construction of the disposal facility and recover the construction cost through the user fees.

In many other nations, waste disposal fees are paid into a government agency, which manages the funds in a segregated account to finance the LLW disposal facilities. Under this concept, fees are paid as the waste is generated rather than when it is sent for disposal. This approach requires that cost estimates, including total costs and the cash flow over time, be prepared to establish appropriate fees to be paid on an annual or per MWh basis. The basis for estimating the funds to be collected should be subject to independent financial audit and to peer-review by waste management experts. Collected fees in excess of cumulative expenses may be invested in low risk securities.

Safety and Environmental Assessments

Safety assessment is a procedure for evaluating the performance of a disposal system and its potential radiological impact on human health and the environment. The safety assessment of near surface repositories should involve consideration of the impacts both during operation and in the post-closure phase. Potential radiological impacts following closure of the repository may arise from gradual processes, such as degradation of barriers, and from discrete events that may affect the isolation of the waste. The potential for inadvertent human intrusion can be assumed to be negligible while active institutional controls are considered fully effective, but may increase afterwards. The technical acceptability of a repository will greatly depend on the waste inventory, the engineered features of the repository and the suitability of the site. The safety assessment will also establish the criteria for waste packaging and acceptance.

The Safety Assessment should conform to the regulatory requirements of Armenia, which are currently being developed. However, it can be anticipated that Armenian regulations will be consistent with safety standards and guidelines provided by International Atomic Energy Agency (IAEA) and the US Nuclear Regulatory Commission (NRC). Guidance on preparing a safety case is available from the IAEA in references 10 and 11 for near surface disposal. These references describe the environmental standards and safety requirements for radioactive waste disposal as well as the methods for safety assessment of the radiological safety of the facility.

5.2 MANAGEMENT OF HIGH LEVEL WASTE

As the name implies, HLW has a high radiation level due to the fission products that have built up in the fuel and transuranic elements produced by neutron absorption in Uranium-238. As these products decay, the radiation levels decrease but other long lived radioactive isotopes are produced which remain radioactive for thousands of years. Because of the high levels of radioactivity, the temperature of HLW may rise significantly, so this factor has to be taken into account in the design of storage or disposal facilities.

The annual operation of a 1000 MWe light water reactor requires an average fuel load of 27 tons of uranium dioxide, containing 24 tons of uranium. A 700 MWe heavy water reactor, using non-enriched fuel would use about 90 tons of uranium. The spent fuel from NPP operation is initially stored at the NPP site in a fuel pool after it has been removed from the reactor. The spent nuclear fuel pool has a cooling and cleanup system that maintains water temperature and clarity. The spent nuclear fuel pool provides shielding from the radiation and cooling to remove decay heat. Over time, the amount of radiation and decay heat diminishes and the spent nuclear fuel can be moved out of the pool to a reprocessing facility or to a concrete shielded independent spent fuel storage installation (ISFSI) where air cooling can be used. Typically the spent nuclear fuel needs to remain in the pool for 5 years to allow decay. Pools generally are capable of holding about ten years worth of spent nuclear fuel. None of the spent nuclear fuel pools are large enough to contain all the fuel that would be discharged over the life of the plant; the cost of building and maintaining a pool of this magnitude would be prohibitive.

From the reactor site, used fuel is transported by road, rail or sea to either an interim storage site or a reprocessing plant where it will be reprocessed. Spent fuel assemblies are shipped in heavily shielded casks. These casks are shielded with steel, or a combination of steel and lead, and can weigh up to 110 tons each when empty. A typical transport cask holds up to 6 tons of spent fuel. Transport casks are carried by truck, rail, or ship.

For different reasons, many plants throughout the world have been unable to transfer spent nuclear fuel for reprocessing and disposal. Many plants now provide interim storage for spent nuclear fuel in ISFSI. The present ANPP has such a facility. These sites are designed for lifetimes of up to 60 years after which time the spent nuclear fuel will need to be transferred to a disposal site where the material will remain isolated for thousands of years. To provide this type of isolation, disposal in a stable deep geologic structure is necessary. Most nations view ISFSI storage as an interim measure that must be followed by a disposal program.

5.2.1 Construction of a Geologic Disposal Facility in Armenia

International policy strongly suggests that, where possible, the geologic disposal site be located in the country where the fuel was used. The IAEA Joint Convention on the safety of spent fuel management and on the safety of radioactive waste management stipulates that; “radioactive wastes…should be disposed of in the country in which it was generated”. Despite this general statement, it may not be possible to provide a safe permanent disposal facility in Armenia.

A major concern in siting a geologic disposal facility is that the area be seismically stable so the wastes will remain out of contact with humans. The IAEA in Safety Standard WS-R-4, *Geological Disposal of Radioactive Waste* [11], states:

> "The geological disposal facility shall be sited in a geological formation and at a depth that provide isolation from the biosphere and from humans over the long term, for at least several thousand years…"

In contrast with this requirement, the entire area of Armenia is in a seismically active zone. This region is part of the Mediterranean-Transasian seismic belt; in fact it is one of the most seismically active zones of the belt. In the past century their have been 182 seismic events with magnitude greater than 4.0. Since the whole area of Armenia is in a zone of relatively high seismic activity, meeting the IAEA standards for a geologic disposal site would not be possible. For this reason alone, it is unlikely that a geological disposal facility would be located in Armenia. In addition, since construction of a geologic disposal facility is an expensive undertaking and with only one nuclear site, the capital cost per unit volume of waste would also be extremely high.

5.2.2 Transporting Spent Nuclear Fuel to the Supplier's Country for Reprocessing or Disposal

In some cases the country which produces the fuel will also reprocess the spent fuel. Commercial-scale spent fuel reprocessing is currently conducted in France, Britain, and Russia. Japan is constructing a reprocessing facility [14]. While these countries reprocess spent nuclear fuel, except for highly unusual circumstances they only reprocess spent fuel where they were the original manufacturer of the fuel. Also, reprocessing agreements require the residue from fuel reprocessing to be returned to the user.

Most countries that are potential fuel suppliers for an Armenia NPP currently have national legislation that prohibits disposing of HLW from other countries. However, this situation may change in the future. For example, both Russia [6] and Kazakhstan [7] have been considering programs to allow import of radioactive waste, including spent fuel for reprocessing or disposal.

Although the Soviet Union had traditionally had spent-fuel take-back arrangements with the Eastern bloc states whose reactors it supplied, Russia's environmental law has prohibited import of spent fuel or nuclear waste for storage or disposal in Russia. In 2001, Russia approved a package of laws that would allow the import of irradiated spent fuel into Russia for "technical storage" and "reprocessing" [15]. Part of the legislation allowed Russia to lease fresh nuclear fuel to foreign customers, leaving the title to the fuel with Russia and thus changing its status from "foreign" to "domestic." However, in 2006, Russian officials announced that Russian origin spent fuel would only be accepted under existing reprocessing contracts or in the context of future reactor sales with spent fuel take-back clauses [16]. This policy would be implemented as part of an international initiative on regional fuel cycle centers.

Conceptually, transporting the Russian origin spent nuclear fuel back to Russia for final disposal is an option for the new Armenia nuclear unit. However, transporting the spent nuclear fuel from Armenia is difficult at this time. The blockades by Azerbaijan and Turkey leave the only usable rail line (to Russia) as one that runs through the Georgian region of Abkhazia and is currently closed to Armenian traffic. However, transportation issues may be resolved in the coming years.

5.2.3 Transporting Spent Nuclear Fuel to an International Disposal Facility

Recently several programs have been put forward to provide one or more international or multinational facilities for the disposal of spent nuclear fuel wastes. The driving force behind these proposals is to prevent the spent nuclear fuel from falling into the hands of those who might divert the fissionable material into nuclear weapons. All of these proposals are in development stages and are not yet fully defined or available for use.

The U.S. Department of Energy Global Nuclear Energy Partnership (GNEP) envisions a consortium of nations with advanced nuclear technologies providing fuel to other countries under a leasing arrangement. International fuel leasing arrangements, where the supplier takes responsibility for the final disposition of the spent fuel, will assure fuel availability. While the spent fuel would not necessarily have to be returned to the fuel cycle country that supplied it, the supplier country would retain the responsibility to ensure that the material is secured, safeguarded and disposed of in a manner that meets shared nonproliferation policies. International partnerships to develop advanced recycling would be based on productive approaches, incentives and safeguards. By participating in GNEP, growing economies can enjoy the benefits of clean, safe nuclear power while minimizing proliferation concerns and eliminating the need to invest in the complete fuel cycle (e.g., reprocessing and enrichment)[(17)].

The IAEA Director General proposed a 3-pronged approach to limiting the processing of weapon-usable material (separated plutonium and high-enriched uranium) in civilian nuclear fuel cycles[(18)]. First, he would place all enrichment and reprocessing facilities under multinational control. Second, he would develop new nuclear technologies that would not produce weapons-usable fissile Third, he proposed considering “multinational approaches to the management and disposal of spent fuel and radioactive waste.” In February 2005, an IAEA Expert Group presented a report, “Multilateral Approaches to the Nuclear Fuel Cycle.” The Expert Group studied several possible approaches to securing the operation of proliferation-sensitive nuclear fuel cycle activities (uranium enrichment, reprocessing and spent fuel disposal, and storage of spent fuel) The group’s suggested approaches included creating co-managed, jointly owned facilities. The report is still under discussion by IAEA Board members.

In January 2006, the Russian Federation President proposed a four point plan of cooperation: The Global Nuclear Power Infrastructure (GNPI)[(18)]. This plan envisioned the creation of international uranium-enrichment centers (IUECs); international centers for reprocessing and storing spent nuclear fuel, international centers for training and certifying nuclear power plant staff, and an international research effort on proliferation-resistant nuclear energy technology. The international fuel cycle centers would be under joint ownership and co-management. As a first step, Russia has created a model International Uranium Enrichment Center (IUEC) at Angarsk. The Angarsk IUEC began operation on September 5, 2007. France is reportedly also considering establishing a similar IUEC on its territory.

In May 2006, six governments (France, Germany, the Netherlands, Russia, the United Kingdom, and the United States) proposed a “Concept for a Multilateral Mechanism for Reliable Access to Nuclear Fuel”[(18)]. The Six Country Concept addressed several future options, all of which are longer term in nature. They include providing reliable access to existing reprocessing capabilities for spent fuel management; multilateral cooperation in fresh fuel fabrication and spent fuel management; international enrichment centers; and new fuel cycle technology development that could incorporate fuel supply assurances.

The European Commission is sponsoring the program: Support Action: Pilot Initiative for European Regional Repositories (SAPIERR) [8]. In the period 2003 to 2005, the EC funded project SAPIERR I was devoted to pilot studies on the feasibility of shared regional storage facilities and geological HLW disposal facilities, for use by European countries. The studies showed that shared regional repositories are feasible, but also that if they are to be implemented, even some decades ahead, efforts must already be increased now. SAPIERR II began in 2006 as a follow-on project to the feasibility studies of SAPIERR I.

In 2002, organizations from five countries inaugurated the Association for Regional and International Underground Storage (ARIUS) to support the concept of sharing facilities for storage and disposal of all types of long-lived radioactive wastes. The mission of ARIUS is to promote concepts for socially acceptable, international and regional solutions for environmentally safe, secure and economic storage and disposal of long-lived radioactive wastes. Since its inception, three other countries have joined ARIUS.

Due to the recent nature of most of these HLW disposal programs they are vague in detail. However it is encouraging that so many of the major nuclear technology countries are considering similar plans. Furthermore, the countries are working together to meld their disparate plans into a single approach. These plans include the development of “new technologies” to transmute the radioactive heavy metals produced into other isotopes that could not be used for nuclear weapons. This process would also reduce the volume of high level waste.

Cost estimates for spent nuclear fuel disposal in multinational repositories have been developed under the SAPIERR program [8]. The total costs for constructing and operating a deep geologic repository would range from $500 to $1,000 per kilogram heavy metal (KgHM). It can be assumed that the fees charged by a multinational repository would be within this range. These disposal costs are comparable to the fees suggested by Russia for the Non-Proliferation Trust (NPT) project, proposed in 1999, of $1,200 to $2,000/KgHM [19]. The NPT fees included substantial profit that was to go to nonproliferation and environmental cleanup activities.

The costs of transportation of the spent nuclear fuel to the multinational repository are significant, although small compared to the disposal cost. Most cost studies for spent fuel transport use a single estimated figure based on mass, which does not consider distance. The reason is that the main elements of transport costs are the capital costs of transport casks and vehicles, preparing the material for movement, and waste reception. The unit cost for international transport of spent fuel to a European regional repository is estimated at $60/KgHM [19].

5.2.4 Recommended Approach to the Management of High Level Waste

Based on the number and types of initiatives currently underway to develop programs for international or multinational facilities for the disposal of spent nuclear fuel wastes, it is reasonable to assume that such a facility would be available to Armenia within the 60 year lifetime of the new nuclear unit. Therefore, the available strategy for management of HLW from the new nuclear unit is to construct an ISFSI facility for dry cask storage at the site, similar to that used for the existing ANPP. After five or more years of storage in the spent nuclear fuel pool, the spent fuel could be moved to the ISFSI. Later when an international disposal location opens, the spent nuclear fuel could be moved from the ISFSI to the international facility. The independent spent fuel storage facility should have a design lifetime of at least 60 years, although the capacity could be built incrementally until the time frame for establishing an international disposal facility becomes better understood.

The total cost for HLW management under this strategy includes the cost of storage, transportation, and disposal fees. Cost estimates for spent nuclear fuel disposal in multinational repositories have been developed under the SAPIERR program (8). The total costs for constructing and operating a deep geologic repository would range from $500 to $1,000 per kilogram heavy metal (KgHM). It can be assumed that the fees charged by a multinational repository would be within this range. These disposal costs are comparable to the fees suggested by Russia for the Non-Proliferation Trust (NPT) project, proposed in 1999, of $1,200 to $2,000/KgHM (19). The NPT fees included substantial profit that was to go to nonproliferation and environmental cleanup activities.

The costs of transportation of the spent nuclear fuel to the multinational repository are significant, although small compared to the disposal cost. Most cost studies for spent fuel transport use a single estimated figure based on mass, which does not consider distance. The reason is that the main elements of transport costs are the capital costs of transport casks and vehicles, preparing the material for movement, and waste reception. The unit cost for international transport of spent fuel to a European regional repository is estimated at $60/KgHM (19).

There are a wide range of estimates for the cost of dry cask storage in an ISFSI. The average cost in Europe is estimated at $100/KgHM in reference 19. The cost of storage in the existing ANPP ISFSI is about $200/KgHM (4). Based on this range of estimates, the cost of interim storage of the HLW is between $2.5 to $5 million per year. This is usually considered as an operating cost for the plant. It can be seen that significant cost savings can be realized by moving the HLW to disposal as early as possible.

Based on the above estimates, the total cost for the HLW management for a 1000 MWe pressurized water reactor would be estimated between $13 and $25 million per year. This includes $10 to $20 million per year in future transportation and disposal fees, which will be paid when the HLW repository becomes available. The future transportation and disposal fees are equivalent to between $1.7 and $3.2 per MWh of electric generation.

In order to ensure the availability of funding for HLW disposal, a special, segregated account will need to be established by the GoA. Annual fees are paid into this account by the NPP operator based on the amount of electricity generated. Establishing the level of these fees will require preparing updated cost estimates, including total costs, cash flow over time, and investment returns on the account. The basis for estimating the funds to be collected should be subject to independent financial audit and to peer-review by waste management experts. Collected fees in excess of cumulative expenses may be invested in low risk securities.

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6. TARIFF ANALYSES AND FINANCIAL PLAN, INCLUDING SURVEY OF POTENTIAL FINANCING SOURCES

The objectives of this study are: (a) to define the key considerations involved in obtaining financing for the new Nuclear Power Unit project (the "Project"); (b) to identify alternatives for financing the project; and (c) to conduct the tariff analyses examining alternative approaches to establishing a new rate structure to provide assurance that the debt for the nuclear power plant project can be serviced through the revenues from electricity sales.

6.1 KEY CONSIDERATION FOR LENDERS AND INVESTORS

In performing this study, a number of financial institutions, which are typically involved in financing power projects, were surveyed. The survey results are presented in Appendix A. This section summarizes the findings of the survey.

Based on discussions with potential lenders and investors in the Project, one of the major concerns is GoA's credit worthiness to support a project of this magnitude. This concern is generally reflected in the Long Term Foreign Currency ratings for Armenia of the major ratings agencies. Moody's maintains a stable Long Term Foreign Currency rating of Ba2, which is below an investment grade rating. Fitch Ratings also maintains a speculative grade Long Term Foreign Currency rating for Armenia at BB. These ratings are much lower than the Fitch's investment grade BBB rating of Bulgaria and Romania, both of which recently developed nuclear power plants. The ratings agencies tend to support the market's perception that Armenia is a high-risk country.

Lenders and investors also expressed concern about Armenia's ability to support debt related to the Project. Armenia's external debt stock as of the end of 2006 is estimated at $1.4 billion or 23% of GDP, most of which is public and publicly guaranteed debt owed to multilateral international organizations such as the World Bank. According to the International Monetary Fund (IMF) 2007 Debt Sustainability Analysis, Armenia is at a low risk of debt distress. However, the total amount of financing required for the project is more than double Armenia's external debt stock and represents approximately 50% of Armenia's GDP. If the GoA were to take on even a small portion of the total financing required, this would put significant stress on their ability to meet future debt obligations. Lenders' and investors' concern that Armenia will have limited ability to support debt for a project of this magnitude is justified based on the IMF data.

GOA must also consider the impact that the NPP Project's debt obligations to foreign creditors and/or dividends to foreign investors will have on its foreign exchange reserves. According to the IMF's most recent macroeconomic analysis, Armenia maintains foreign currency reserves of approximately USD 1.5 billion. The conversion of drams to hard currency for the repayment of debt and return on equity, which may require several hundred million USD annually (this based on a project cost of $4 billion or more), would cause a substantial drain on the country's reserves. This drain in reserves would need to counter-balanced by an increase in net exports or foreign currency borrowings. While an increase in exports is sustainable, it generally takes considerable time and resources to increase net exports. On the other hand, foreign currency borrowings may be available more immediately but are not sustainable over the long term. In this regard, payment obligations for the Project may pose a challenge for the GoA.

In addition, potential lenders and investors consistently noted that considerable resources and attention must be devoted to several agreements in order to ensure that the risks to the Project are minimized regardless of the structure that is pursued. These agreements include:

- Engineering, Procurement and Construction (EPC) Contract: A fixed price, date-certain contract with an experienced contractor and adequate performance guarantees is desirable. However, this could be prohibitively expensive in today's market. If a fixed-price contract is unavailable, the Project Construction Cost estimate should include additional outlays associated with price escalation in addition to general cost contingencies (see "Construction Cost Contingencies and Escalation" section below).

- Operations & Maintenance: Operations & maintenance should be undertaken by a third party that is regarded as a world-class player. This could be achieved either directly by involving the party as a sponsor/investor in the Project or via a third-party O&M Agreement.

- Full Recovery of Plant Costs: The full recovery of the plant's fixed and variable costs (including decommissioning costs) must be guaranteed as per national legislation (PSRC Resolution 125 et al.)

The targeted lenders also frequently identified several other considerations, which require up-front planning on the part of GoA. These considerations include the following:

- Sovereign Guarantees: It is likely that GoA will need to post sovereign guarantees for the full amount of Project debt, regardless of the ownership and financing structure chosen. A sovereign guarantee, which represents a full-faith-and-credit guarantee of project debt repayment provided by Armenia's Ministry of Finance or other competent authority, will assure Project lenders of the GoA's commitment to the Project. While GoA may not have the full capability to repay the project debt (which could amount to $2 billion or more), many of the potential lenders to this project are government-backed institutions whose lending decisions are driven by political as well as commercial factors. Many of the regulatory risks associated with the Project are within the GoA's ability to control, therefore a sovereign guarantee will somewhat mitigate the perceived Project risks from the perspective of lenders and investors. These guarantees will be treated as contingent liabilities, which will have a much lower impact on the GoA's credit rating in comparison to a direct liability. However, the GoA's ability to post such guarantees is also a major concern as discussed above.
  Armenia's covenants with the IMF restrict GoA's ability to "contract or guarantee non-concessional external debt". This IMF covenant would apply not only to any GoA direct borrowings but also any GoA sovereign guarantees of foreign debt associated with the Project if structured as a special-purpose borrower. In the event that lenders require such guarantees (which appears to be the most likely case based on our discussions to-date), IMF's consent to the transaction will be required as a pre-condition to loan approval and disbursement.

- Decommissioning Cost Provisioning: The cost of decommissioning should be factored in up-front in order to ensure adequate funds are available at the time of decommissioning. A 60 year sinking fund is recommended. An insurance policy that caps the cost of decommissioning, such as AIG's policy, should also be considered.

- Insurance Coverage: AIG, Lloyd's, and Zurich can underwrite all-risk coverage for Material Damage including property, construction all-risk, and erection all-risk for machinery/plant construction extended to third parties for all phases of the nuclear fuel cycle. Civil Liability Insurance can be arranged for damages incurred to third parties as a consequence of NPP operation or from nuclear material transportation. In addition, Political Risk Insurance is also available in the case of damages to assets due to political violence.

- Spent Fuel Disposal: A spent fuel dry storage installation with at least 20 years of fuel storage capacity is recommended for the new nuclear site. After 20 years, the spent nuclear fuel could be moved from the independent spent fuel storage facility to an international facility (IAEA, U.S., Russia, etc.) currently in the planning stage. The location of the final disposal is important to many potential lenders and investors due to the political implications of nuclear waste disposal. In the IPP case described below, we recommend mitigation of environmental risks to lenders and private-sector investors through the creation of a GoA organization to take possession of spent fuel when it goes into dry storage and to hold the dry fuel storage facility assets, with an agreement to collect fees for storage, transportation and disposal of the spent fuel.

- Nuclear Liability: Under Armenian Atomic Energy Law, types and amounts of liability are determined by acts of GoA legislation. Nuclear damage compensation for any accident "must not be less than" amounts established by international treaties to which Armenia is a Party. It is the role of the GoA to ensure compensation obligations. According to discussions we have had with commercial banks, it may be difficult to obtain insurance coverage to cover third-party liability associated with nuclear incidents during construction and operations. Our understanding is that most insurers carve out nuclear incidents from the coverage. If this is the case, the Project company will be exposed to this risk. Lenders will require a plan from the Company and Sponsors to mitigate this uncovered risk, e.g. through contingent equity support for the life of the loan. Delphos International recommends that the Project budget a sinking fund of SDR 300 million (maximum liability of operator under Article 7 of the Paris Convention as amended by the Brussels Supplementary Convention of 1982), established up-front, or in the form of Letters of Credit from the Project sponsors.
- ECA percentage cover of commercial bank exposure to Project: Under an Export Credit Agency-supported financing structure, the ECAs (who have strong credit ratings) provide their full-faith-and-credit guarantees to commercial lenders who lend to the Project. Some of the ECAs provide 100% coverage, meaning that if the

Project doesn't repay the debt, the commercial lenders will be covered for 100% of the amount of the principal and interest in default. However most ECAs provide less than 100% cover to commercial banks, meaning that if the Project defaults, the commercial banks are not covered by the ECAs for the full amount of the default. This in turn requires that a commercial bank have a country exposure ceiling (i.e. the cumulative maximum exposure they are permitted to have vis a vis borrowers in a particular country) for Armenia. Most international banks do not have active lending operations in Armenia and thus have had no reason to go through the process of assessing country risk etc in order to establish such a ceiling.

US Exim, Canadian EDC (through its direct lending program) and the UK ECGD are among the few ECAs that provide 100% commercial + political cover. Other ECAs such as NEXI, EKN, CESCE, COFACE, ATRADIUS, EULER HERMES, and SACE all provide less than 100% commercial cover, which requires commercial banks to have a country exposure ceiling for Armenia.

6.2 CONSTRUCTION COST CONTINGENCIES AND ESCALATION

The Project construction cost should factor in not only base construction cost estimate but also cost contingencies that could be higher or lower depending on the level of detail of the engineering and design that form the basis for the cost estimate. Project cost should also factor in price escalation to the extent that it is impossible or prohibitively expensive to obtain a fixed-price EPC contract. These budgeting issues should be addressed in the financial model as part of the project cost with implications for the levelized tariff. Discussion of each follows:

Construction Cost Contingency. Contingency involves a cost allowance for indeterminate elements in the construction cost estimate and should be related to the level of design, degree of technological advancement, and the quality/reliability pricing level of given components. The American Association of Cost Engineers International (AACEI) suggests 15% as a standard contingency level for construction cost. Revision 4.2 of the "Cost Estimating Guidelines for Nuclear Energy Systems", as prepared by the Economic Working Group of the Generation IV International Forum, suggests that the amount of contingency should be higher in the case of preliminary cost estimates and can be lower once full engineering and design has been completed. To ensure a 90% probability of success (i.e. that final construction cost does not exceed the base cost + contingency), a finalized estimate requires approximately 10% of added contingency, but a detailed cost estimate requires 20% contingency and a preliminary cost estimate requires 30% contingency. It is recommended that a contingency of at least 15% be included as an adder to the base construction cost estimate.

Price Escalation. Escalation represents an increase in the market costs of supply of components making up the construction cost (e.g. materials, equipment, machinery and labor). Note that this is additional to contingency, which involves an allowance for indeterminate elements in the construction cost estimate and should be related to the level of design, degree of technological advancement, and the quality/reliability pricing level of given components. Price escalation forms part of Total Capital Investment Cost, while contingencies are treated as part of the Overnight Construction Cost.

Escalation does not form part of the economic analysis (which assumes constant dollars). However for purposes of the financial analysis, to the extent that price escalation is not included in the contract price per the terms of the EPC Contract, escalation needs to be considered since it impacts the anticipated cash requirements from a project financing, which in turn must be covered by sources of project funding (equity, debt, or net cash flow from operations).

Current market conditions make it difficult (other than at prohibitively high costs) to obtain fixed-price contracts that have no escalation provisions, which effectively insulate the Project from all market fluctuations for various materials and equipment.

Table G.1.5 (“Escalation Adjustment Factors”) of the Economic Working Group of the Generation IV International Forum, rev. 4.2 of “Cost Estimating Guidelines for Nuclear Energy Systems” shows the development of different price indices affecting various components of nuclear power plant construction. Overall the increase was 30.9% during the 6-year period of 2000 to 2006. If we assume a straight line construction drawdown schedule, the applicable amount of escalation during a 6-year construction period would thus be approximately 15%.

Therefore, it is recommended that a 15% allowance for cost escalation be included as an adder to the base construction cost estimate in addition to the cost contingencies mentioned above.

6.3 TARIFF STRUCTURE

Under Armenian tariff regulations, the tariffs that Electric Networks of Armenia (“ENA”) must pay to electric energy generating companies (“GenCos”) are determined by the methodology laid out in PSRC Resolution No. 125 N from September 16, 2005. The methodology is broken down into two phases including a calculation of the revenue requirement and a cost analysis.

The revenue requirement, or revenue that Generating Companies are allowed to earn from tariffs, is intended to be sufficient to cover all the operating costs and allow for a reasonable profit. As such the revenue requirement is a function of allowed costs, depreciation and allowed profit. Allowed costs include operation and maintenance, fuel, fuel disposal, decommissioning fund costs, taxes and other justified costs. Depreciation is calculated in a linear manner. The allowed profit is a function of a profit calculation base and an allowed rate of return. The allowed rate of return is based on the average value of borrowed capital and equity as well as the capital structure. It is assumed that the allowed profit will meet the minimum IRR required by investors based on the risk-free rate of return, the market premium for U.S. or EU markets, the levered industry beta, the country premium for Armenia, and the project risk premium.

The next phase of the tariff-developing process is the GenCos' cost analysis. This consists of two parts, but only the second part, costs classification is relevant for nuclear plants. Costs classification separates costs into fixed and variable costs. This is necessary as the plant will incur certain fixed costs regardless of the amount of capacity that is dispatched to the national grid as well as variable costs based on this delivered energy.

The final section of PSRC No. 125 addresses tariff rate calculation. A two-part tariff system is utilized for a nuclear power project, because the System Operator may have the plant dispatch power on an instant basis. The tariff is broken into an electric energy rate that covers the variable cost of delivered energy and a capacity rate that covers contractual available capacity.

These existing regulations appear to be sufficient to support full cost recovery to the Project. Therefore, the Project would be viable for project financing based on tariff recovery. However, ENA will also need to pass tariffs through to end users. Given that most existing plants are fully amortized, the new NPP (which will represent a large portion of Armenia's installed capacity) will entail a significant increase in the blended tariff that ENA charges to end users. This raises the fundamental issue of demand risk, i.e. the willingness to pay of consumers in Armenia, which has potential implications for ENA's long-term financial viability given the sheer size of the NPP. Lenders to the NPP should be able to get comfortable with this risk based on power sector modeling analysis that considers the price elasticity of demand, among other factors.

6.4 PROJECT OWNERSHIP AND FINANCING STRUCTURES

Based on input from the Government of Armenia ("GoA") and numerous financial institutions three potential ownership structures have been identified for the project. These structures are as follows:

Public Investment: Wholly-owned NPP by the GoA

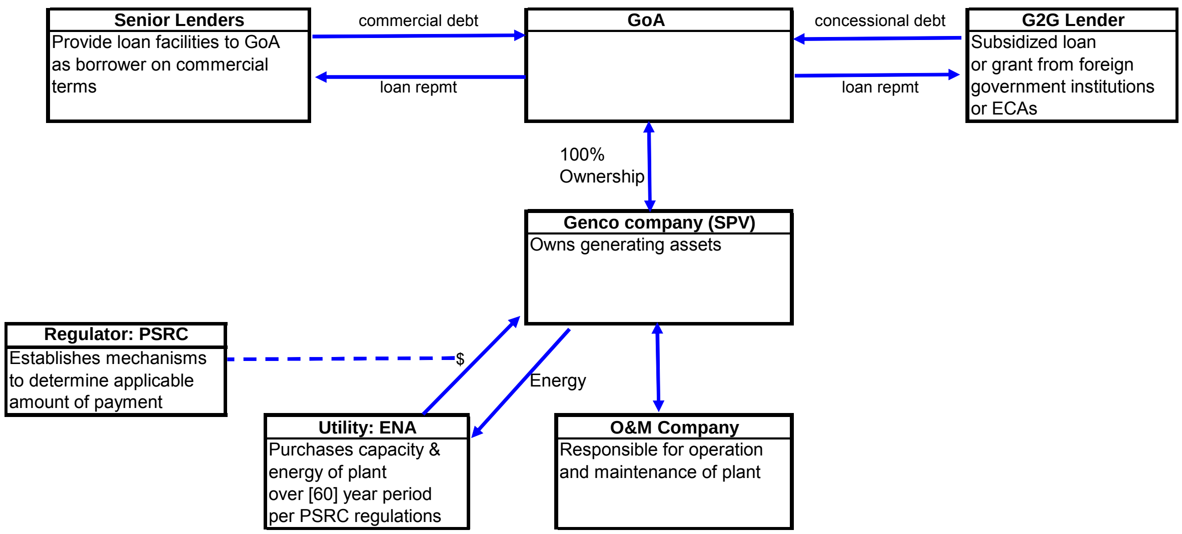
Public Private Partnership (PPP): Joint Venture ("JV") between the GoA and private sector investors

Independent Power Producer (IPP): Wholly-owned by a private sector entity

These ownership structures are discussed in the following sections.

<u>Ownership and Financing Structure A: Public Investment</u>

The following chart illustrates the likely structure of a wholly government owned plant:



In this scenario GoA sources a mixture of Export Credit Agency ("ECA") commercial debt and government-to-government ("G2G") concessional debt and/or grants to finance the development of the Special Purpose Vehicle ("SPV"). The SPV is a separate company established to operate the plant or the electricity generating company ("GenCo"). This company owns all of the generating assets. GoA must obtain an International Monetary Fund ("IMF") waiver for the ECA(s) to proceed with transaction on commercial terms and provides a sovereign guarantee of its obligations.

The main advantages of this structure are as follows:

The lowest cost of financing.

This low cost of financing allows for lower tariffs, which results in a lower cost of electricity to end-users.

Shortest time to financial closing as the structure is the least complex.

The main weaknesses of this structure are as follows:

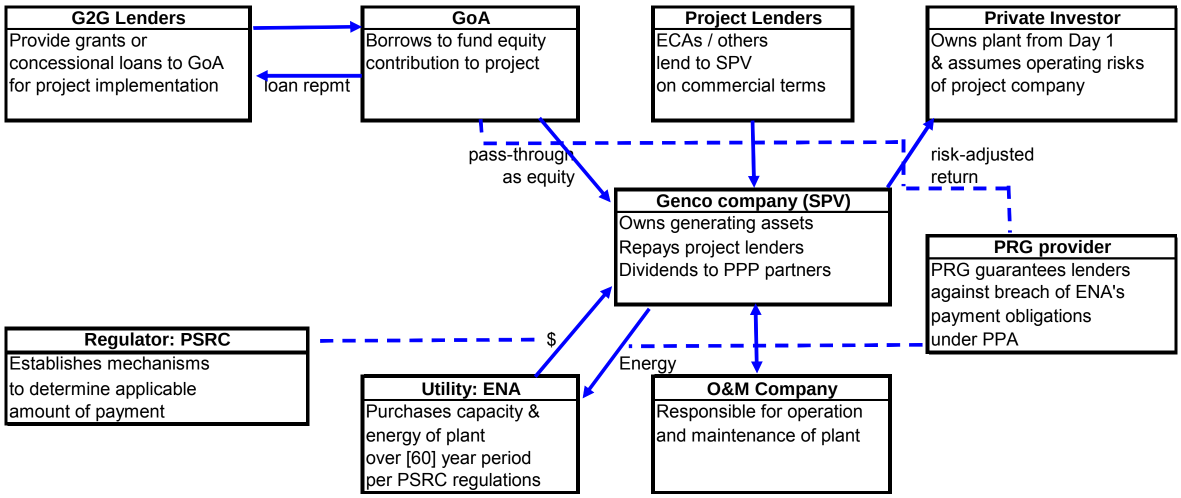
Large fiscal burden to GoA due to direct obligation on debt associated with the Project.

The potential default of IMF covenants would require an IMF waiver if external debt does not meet the concessionality threshold established in Technical Memorandum of Understanding.

It is probably unrealistic to expect concessional loans or grants for more than a small percentage of the total Project costs, given the large overall amount of required financing.

Ownership and Financing Structure B: Public-Private Partnership (PPP)

The following chart illustrates the likely structure of a Public-Private Partnership in the form of a JV between the GoA and private sector investors:



Under this scenario GoA sources a concessional loan and/or grants for a small percentage of the Project costs, and applies the proceeds to fund a portion or all of its equity contribution to the SPV as minority shareholder. Private investors will take on the majority of equity funding. ECAs provide senior debt to the SPV via buyer credits. A third party provides a Partial Risk Guarantee ("PRG") to guarantee lenders of ENA's payments to the SPV per PSRC cost-recovery methodologies, with GoA counter-guaranteeing the PRG provider. In addition, GoA provides a comfort letter stating that electricity regulations will ensure future cost recovery to GenCos. Alternatively, GoA could provide an outright guarantee of the ECA loans.

The main advantages of this structure are as follows:

Relatively low weighted average cost of financing.

Low tariff relative to the IPP structure, due to the lower return on investment required by GoA.

Lower fiscal burden when compared to 100% public ownership.

Counter-guarantee represents a contingent liability but should not factor into the IMF's Debt Sustainability Analysis.

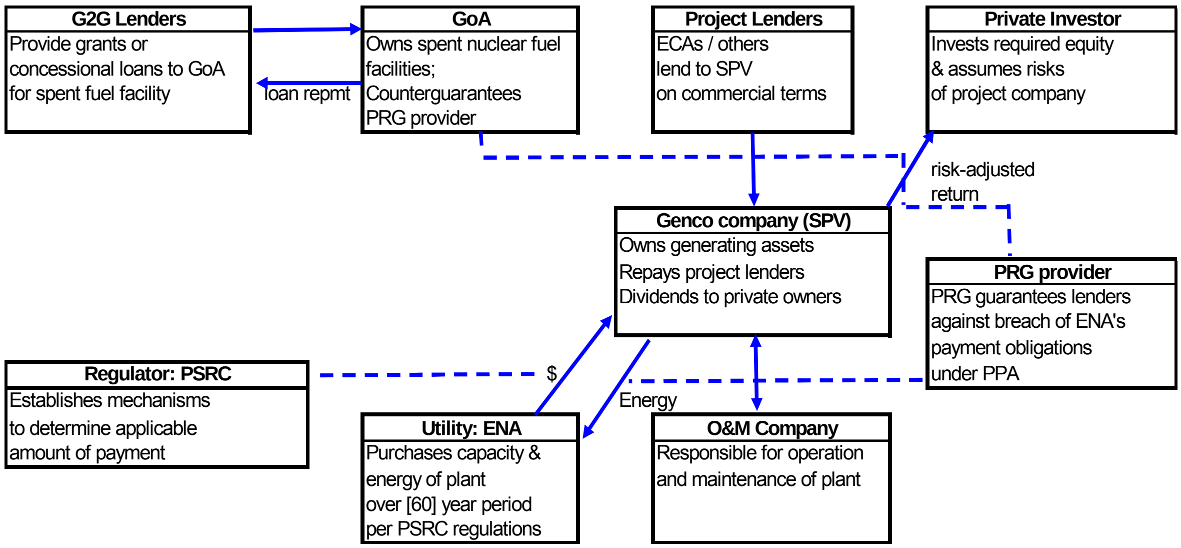
The main weaknesses of this structure are as follows:

More explicit financial burden on GoA than the IPP structure.

The higher complexity results in a longer time to financial closing when compared to 100% public ownership.

<u>Ownership and Financing Structure C: Independent Power Producer (IPP)</u>

The following chart illustrates the likely structure of an IPP, wholly owned by the private sector:



In this third scenario, GoA relies on the private sector to build, own and operate the Project. This requires debt to a privately held SPV, as well as equity contributions from private investors. GoA has no ownership in the SPV. As with the PPP structure, a third party provides a Partial Risk Guarantee (PRG) to guarantee lenders of ENA's payments to the SPV per PSRC cost-recovery methodologies, with GoA counter-guaranteeing the PRG provider. In addition, GoA provides a comfort letter that electricity regulations will ensure future cost recovery to GenCos. GoA could fund this out of G2G concessional debt/grants and/or its own budgetary resources.

In terms of mitigating the risks to an IPP project lender or private investor, one concern is the incremental liability (e.g. environmental liability) of operating the spent nuclear fuel facility. Even if this facility is financed as part of the overall project, we believe it would help mitigate this risk by creating a separate legal entity to hold these assets with an agreement for the facility to store the spent fuel from the NPP at a predetermined price. In fact, GoA would have a greater chance of attracting concessional loans and/or grants for such a facility as it can be characterized as an environmentally oriented project.

The main advantages of this structure are as follows:

Lowest financial exposure to GoA.

Counter-guarantee represents a contingent liability but should not factor into the IMF's Debt Sustainability Analysis.

Shift operating risks from the GoA to the private sector.

Private sector efficiency.

The main weaknesses of this structure are as follows:

Highest tariff to ENA due to high cost of financing.

Slow execution due to the high risks.

The following table compares and contrasts the three potential structures discussed above:

Potential Structure	Financing Source	GoA Obligations	Advantages to GoA	Risks to GoA
Public: Wholly Owned by GoA	ECA commercial debt and G2G concessional debt/grant	100% of debt	Lowest cost of financing, shortest time to closing, lower tariffs	Large fiscal burden, potential default on IMF covenants
Public/Private: Public Private Partnership (PPP)	Private Sector Investor/ECA commercial debt, G2G concessional debt/grant, private sector equity	Concessional debt. Counter-guarantee payments by ENA to SPV or outright guarantee of ECA loans.	Relatively low weighted average cost of financing, low tariff compared to IPP, low fiscal burden compared to government owned	Higher complexity, higher fiscal burden than IPP, slower execution than government owned
Private: Independent Power Producer	Private Sector Investor/ECA commercial debt, private sector equity	Counter-guarantee payments by ENA to SPV.	Lowest explicit budget exposure, private sector efficiency	Slowest execution, higher cost of capital leading to higher tariffs

6.5 CONCLUSIONS, RECOMMENDATIONS AND NEXT STEPS

6.5.1 Recommended Ownership Structure

Of the three ownership scenarios highlighted above, the Public-Private Partnership structure would be the most appropriate fit due to GoA's likely need to directly guarantee the Project debt. If this is the case, GoA could act as direct borrower for a portion of the Project debt and could push this down to the Project company as its equity contribution. Private investors (strategic, financial or both) would be brought in to provide the bulk of the required equity contributions, as well as O&M expertise.

Note that for conceptual purposes, the PPP structure as shown above involves GoA extending an indirect counter-guarantee of ENA's payment obligations, which is one way around the IMF covenant restricting GoA's "contracting or guaranteeing of non-concessional external debt". But it would be more conservative to anticipate the "fallback" position of a direct guarantee of the Project debt by GoA.

As the Project is further structured and developed, GoA should reconfirm the availability in the market for a bankable Partial Risk Guarantee from an international financial institution. The World Bank Group has taken the greatest strides in developing this structure, yet the World Bank is not able to support nuclear power projects due to current policy restrictions.

In the event that PRGs are not available from either public or private sector institutions, GoA could explore the acceptability of a structure whereby it guarantees ENA's payment obligations under PSRC regulations without support from a PRG provider. However, given GoA's sovereign rating is several steps below investment grade it is unlikely that such an indirect guarantee would provide sufficient comfort to lenders on a stand-alone basis.

6.5.2 Recommended Sources of Funding

For the debt portion of the Project financing, it is concluded that ECA backed loans are the only feasible source of debt financing for the Project. Based on discussions with government-backed financial institutions, commercial banks, investment banks and insurance companies including those listed in Appendix A, it is clear that loans from other than ECAs are not likely at this juncture.

For the <u>equity portion</u>, assuming a 3:1 capital structure, 25% of Project Costs will need to be financed by equity from private sector co-investors together with GoA. It is not likely that the GoA equity share can be raised through borrowing and it should be assumed that GoA will need to come up with most or all of the equity from tax revenues or through a special surcharge on electricity sales for the existing plant.

As mentioned earlier in this report, GoA is currently restricted by IMF covenants from the "contracting or guaranteeing of non-concessional external debt". This covenant applies should GoA wish to borrow from foreign sources and contribute the proceeds as its equity investment. By implication, One possibility for GoA to free up cash for the new NPP is by obtaining grants or concessional loans (e.g. from Euratom) for environmentally oriented expenditures, e.g. related to the creation of a new nuclear spent fuel facility or for the decommissioning of the Metsamor plant. The GoA funds that would otherwise be spent on these projects could then be made available for investmen in equity of the Project.

The aforementioned IMF covenant equally applies to any GoA sovereign guarantees of <u>foreign debt portion</u> associated with the Project. Therefore, in the event that lenders require such guarantees (which appears to be the most likely case based on our discussions to-date), IMF's consent to the transaction will be required as a pre-condition to loan approval and disbursement.

Based on the discussions with financial institutions to date, it is recommended that a combination of funding from two export credit agencies, U.S. Ex-Im Bank and Export Development Canada ("EDC"). It is important to note that the relevant export content (goods or services) must originate from the U.S. or Canada to be eligible for funding from these ECAs based on their content policies. Other ECAs could be brought in to support content sourced from Europe, Japan, Korea or China. In the case of Ex-Im Bank, this financing option would likely have the following terms and conditions:

Borrower: Project company

Guarantor: GoA

Amount: Lesser of i) 100% of export content, ii) 85% of contract price, or iii) 75% of project cost (in the case of a direct guarantee by US Ex-Im bank to the SPV).

Currency: U.S. Dollars

Repayment Period: Up to 15 years, consisting of equal semiannual payments of principal.

Eximbank Exposure Fee: 29.67% [58] of the loan amount, payable up-front or as-drawn. The exposure fee is financeable as part of eligible content.

Interest Rate: USD LIBOR + 0.25%-0.50% per annum

The application process for both lenders can be summarized as follows:

U.S. Ex-Im Bank:

There are several stages required to apply for U.S. Ex-Im Bank long-term financing. As a first step, a preliminary commitment ("PC") must be obtained from Ex-Im Bank (Note that the PC is required for the export of goods for a nuclear power plant). The PC is an offer of Ex-Im Bank financing subject to the award of the export contract and Ex-Im Bank's review of a Final Commitment application ("AP"). The foreign buyer (the project company), the exporter, or a financial advisor may apply for the PC. The processing fee for a PC is equivalent to 0.1% of the requested amount of the financing (excluding the Ex-Im Bank exposure fee), up to a maximum of $25,000. If the foreign buyer or borrower applies for a PC, the processing fee may be paid by the U.S. exporter. This fee will be rebated if and when an AP is approved by Ex-Im Bank.

In the next stage, an AP can be applied for once the export contract has been awarded. The AP is an authorization of financing by Ex-Im Bank. The applicant for an AP is responsible for payment of Ex-Im Bank's commitment fee for a loan or guarantee or facility fee for a credit guarantee facility. Only the foreign borrower may apply for an AP for an Ex-Im Bank direct loan. The foreign borrower or guaranteed lender may apply for an AP for a guarantee. If the lender has not been selected, only the borrower may apply for an AP for a guarantee. In the case of a guarantee, a commercial lender acceptable to U.S. Ex-Im Bank must be identified.

Applications can be downloaded from the Ex-Im website: http://www.exim.gov/tools/appsforms/loanguar.cfm**.** Original signed applications can be submitted by mail with a check or money order made payable to the Export-Import Bank of the U.S. to:

Export-Import Bank of the U.S.
Attn: Credit Applications and Processing
811 Vermont Avenue, N.W.
Washington, D.C. 20571

U.S.A.

Additional information is available through Ex-Im Bank's Structured and Project Finance Division at +1-202-565-3690 or on the website: http://www.exim.gov/tools/how_to_apply.cfm

Export Development Canada ("EDC")

[58] Indicative quote provided by U.S. Eximbank was 32.64% based on an 84-month drawdown period and 15 years repayment for exposure fee category 6 (Armenia is currently category 6). Delphos International has adjusted the estimate downwards to 29.67% based on a shorter construction period.

As a first step AECL should submit a definitive request to EDC, in order for the project to take on national importance based on economic benefits to Canada. This would allow for increased availability of funds and willingness to support the Project. A project of this size would be handled by the Project Finance department of EDC. Although there is no specific application form for project financing, the following information must be submitted in order to apply for project financing:

a financial model clearly detailing the sources of revenue;
market and feasibility studies;
an insurance review;
an independent engineer's report;
an environmental assessment; and
details of Canadian content and/or ownership.

Additional information is available on the EDC website:
http://www.edc.ca/english/financing_project_finance.htm or by contacting EDC directly:

Export Development Canada
151 O'Connor
Ottawa, ON Canada
K1A 1K3

+1-613-598-2500

6.5.3 Cost Budgeting Recommendations

The Project cost budgeting recommendations from this report are:

- Include an appropriate level of cost contingency (in the range of 10% - 30%, depending on the degree of detail of the construction cost estimate) as an adder to the base construction cost estimate.
- Include a 10%-15% allowance for cost escalation in addition to the cost contingencies mentioned above.
- Budget a sinking fund of SDR 300 million to cover the Project's liability to third-parties in the event of a nuclear incident.

6.5.4 Recommendations regarding Tariffs / Cost Recovery Mechanisms

- PSRC cost recovery mechanisms should be further analyzed, and if necessary modified to ensure a rate of return on private investment (i.e. equity IRR) for new nuclear power projects in at least the high teens (which is the minimum level likely required to attract private investors to the Project).

6.5.5 Recommended Next Steps

- nitiate discussions with IMF regarding a waiver of the IMF covenant restricting GoA from contracting or guaranteeing new non-concessional external debt. GoA should raise the profile of this Project to the highest level, explain why a new NPP is the best option to ensure continued sustainability of the country's power sector, and present a well-reasoned, bankable plan for the Project's financing with Letters of Intent from lenders and investors as relevant.

- GoA should continue discussions with G2G lenders (whether multilateral institutions or foreign governments) to explore possibilities for sourcing funds on a concessional basis, the proceeds of which would be used to fund the NPP's construction cost. Any shortfall should be met with an electricity tariff surcharge or own tax revenues.
- GoA should initiate informal discussions with U.S. Eximbank, EDC, NEXI and other ECAs as potential guarantors (or direct lenders) to the Project. Such discussions should be initiated only after initial content analysis has been completed, so that the options are known for sourcing of goods and services from the relevant countries and their estimated costing.
- Follow-on analysis should be conducted to ascertain which international commercial banks have established an exposure ceiling for borrowers in Armenia. This is relevant for understanding the feasibility of support from ECAs such as Japan's NEXI, where a commercial bank lending under such cover would still be exposed to the project borrower in a certain percentage (please refer to "<u>ECA percentage cover of commercial bank exposure to Project" section for a discussion of the issue)</u>.
- Follow-on analysis should be conducted with respect to insurance companies' willingness to cover third-party liability related to nuclear incidents.
- Further refine the project construction cost estimate, which will allow for a reduction of contingency to 10%.
- Follow-on analysis to determine the cost of an EPC Contract with no escalation provisions (i.e. contractor absorbs such risks under a fixed contract price).

6.6 TARIFF ANALYSES

6.6.1 Weighted Average Cost of Capital

The Weighted Average Cost of Capital (WACC) is calculated as the internal rate of return (IRR) of all the future cash flows to and from the lender as well as the equity cash flows to and from the investor. The WACC represents the average of the interest cost of debt and the return on equity necessary to attract investors to the project.

The total Project costs are based on the hard cost for construction of the plant as well as the soft costs related to the Project. The soft costs include exposure and commitment fees to U.S. Ex-Im Bank, interest during construction (IDC), debt service reserve account, working capital and legal/consulting fees. The exposure fee makes up the largest component of the soft costs after IDC based on the terms of the loan from Ex-Im Bank.

It is assumed that the Project's capital structure will be 3:1 debt to equity and that 100% of the debt will be sourced from U.S. Ex-Im Bank. The following table illustrates the expected terms of Ex-IM Bank debt:

Table 6.1, Ex-Im Bank Export Credit Loan Terms

Loan Terms	Value	Comment
Loan Duration	15 years	Not including grace period during construction
Grace Period	6 years	Interest Only
Exposure Fee	29.37 %	Risk Increment Level 0 with sovereign guarantee
Commitment fee	0.5 %	Per year
Interest Rate	5.1 %	Swapped out LIBOR
Principal Payment	2 per year	Principal payments begin after grace period

The Exposure fee of 29.37% is based on the risk increment level 0, which is extended to sovereign borrowers such as the GoA. In the case of the PPP and the IPP, both structures will also qualify as sovereign borrowers due to the sovereign guarantees that must be provided by the GoA for each of these structures. Additional discussion on the terms and conditions of Ex-Im Bank debt is presented in section 6.5.2. It should be noted that with the one time exposure fee and annual commitment fee, the cost of debt is for the Ex-Im loan is approximately 10 percent.

For the case of GoA owned plant, the cost of equity for the GoA is assumed to be 10%, which is the World Bank's standard for developing countries. With the cost of debt for an Ex-Im loan the WACC would be 10 %. The cost of financing for this scenario is the lowest, since the GoA's cost of equity is lower than the cost of equity from private investors.

For the case of an IPP project, the equity return to the investors must be higher in order to attract private investors and compensate them for the risk of the project. Based on the results of a project risk analysis performed by Delphos International, the minimum rate of return for private investors is 18.2%. The cost of debt remains unchanged since Ex-Im Bank treats the IPP as a sovereign borrower due to the sovereign guarantee provided by GoA. The private investors account for all of the 25 % equity investment in the Project. As a result, the WACC calculation is 14.7 %, considerably higher than for the GoA ownership. However, this ownership scenario has a much lower fiscal burden on the government's resources.

For the PPP scenario, the cost of equity for GoA also remains at 10% and the cost of equity from private investors is 18.2%. However, because the private investors only provide half of the equity for the project, the WACC is 12.4 %. The WACC is more than 2% higher than GoA scenario, as additional dividends must be paid out to private investors in order to meet their hurdle investment rate of 18.2%. The resulting tariff is more than 2% lower than the IPP scenario, since the combined cost of equity is still below the cost of equity solely for private investors.

6.6.2 New NPP Wholesale Tariff Analysis

To estimate the wholesale tariff for the new NPP, Delphos International developed a financial model of the cash flows for the project from start of construction through plant shutdown after 60 years of operation. The financial model calculates the tariff for the sale of electricity that would be necessary to cover all cash flows including loan principal and interest payments and dividends on the equity financing. The financial model is based on a number of assumptions, which are summarized in table 6.2 and discussed in the following sections.

Table 6.2, Assumptions used in Tariff Financial Model

Parameter	Value
Generation Assumptions	
Net Capacity	1,000 MWe
Capacity Factor	90 %
Net Saleable Energy per Year	7,884 GWh
Operating Cost Assumptions	
Fuel Cost	$5.00/MWh
Fuel Disposal	$1.00/MWh
Annual O&M Cost	$59 million
Decommissioning Assumptions	
Decommissioning Cost	$500 million
Life of Decommissioning Fund	60 years
Escalation rate for decommissioning cost	4 % / year
Interest rate on decommissioning Funds	8 % / year
Construction Assumptions	
Overnight Construction cost @ $3000/kwe	$3 billion
Construction Contingency @ 15%	$450 million
Construction Spending Profile (Months)	
0	8.00%
1 to 12	20.50%
13 to 24	23.50%
25 to 36	20.50%
37 to 48	11.50%
49 to 60	11.00%
60 to 72	5.00%
Financing Assumptions	
Debt	75 %
Equity	25 %
Debt Term (not including grace period)	15 years
Interest Only Grace Period	6 years
Debt Equivalent Interest Rate	10 %
First Disbursement Date	January 2011
Equity Rate of Return GoA	10 %
Equity Rate of Return Private Investor	18.2 %
Income Tax Rate	20%
VAT	0

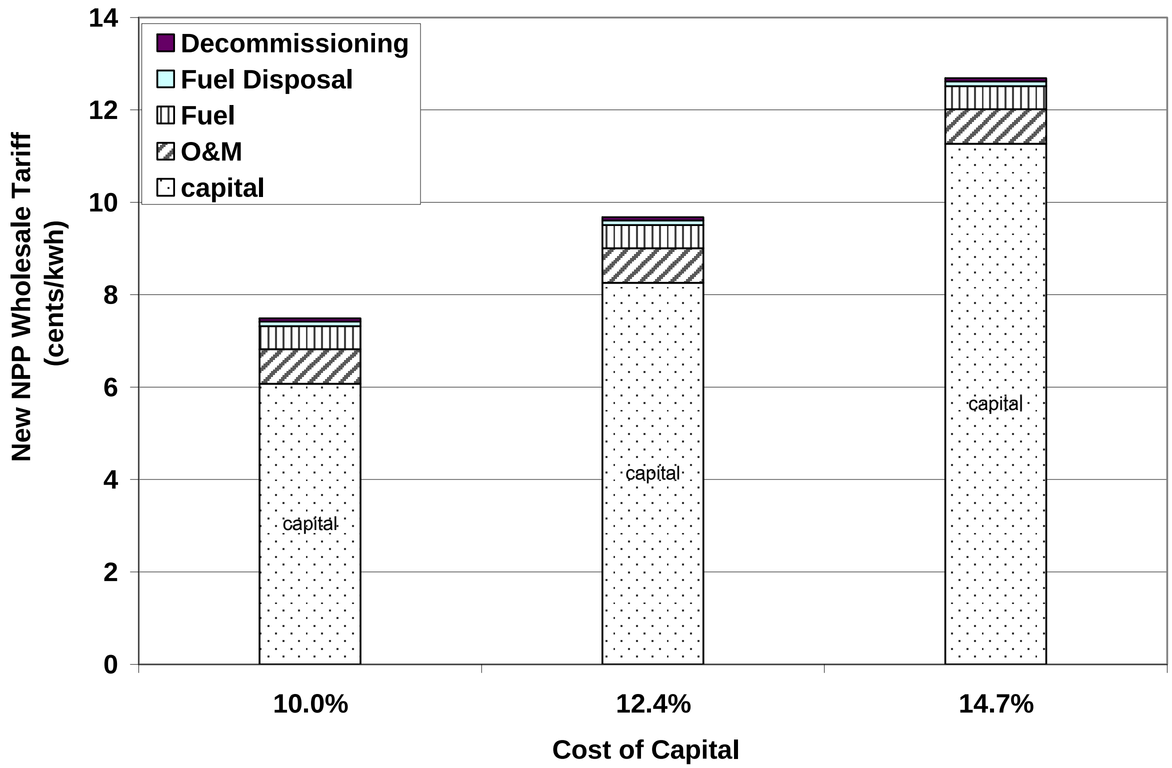
The plant assumed in the model is a 1,000 MWe NPP with an overnight construction cost of $3,000 per kWe. This size and cost are in the middle of the range of designs reviewed in Section 1 of the IPS. Provision for a 15 percent cost contingency was added to the overnight cost estimates.

The construction of the NPP is assumed take six years, with the first during which time funds will be spent to buy the equipment, materials, and construction services. The Construction spending profile is discussed in section 1.4 of Section 1 of the IPS. During the construction period, interest on the money borrowed and owner's investment will accrue and must be paid by additional borrowing. This interest during construction (IDC) will depend on the WACC and will range between approximately $1.8 for the GoA scenario and $3.0 billion for the IPP scenario.

The financial model assumes that the NPP is financed with 75 percent debt at an interest rate of 10 percent from Export Credit Agencies of the country or countries of the suppliers. The remaining 25 percent of the project finance is provided as equity from the owners. The cost of the equity financing depends on the ownership structures as discussed in section 6.6.1. It is assumed that the owners will pay income tax at a rate of 20 percent, and the rate of return on equity is after payment of income tax. However, it is assumed that no value added tax (VAT) will be paid for the construction or operation of the NPP.

The results of the financial model tariff estimates for the NPP are shown in figure 6.1 for the three ownership scenarios. For the GoA scenario, the wholesale tariff for the new NPP would be about 7.5 cents per kWh. For the PPP scenario, the tariff would be 9.7 cents and for the IPP case, the tariff would be about 12.7 cents. As shown in the figure, the payment of interest and principal on capital is by far the largest component of the wholesale tariff.

Figure 6.1, New NPP Wholesale Tariff for Different Values of WACC



6.6.3 System Generating Costs

An analysis of the total cost for generation in the Armenian system was performed using the system planning models developed for the LCGP. The system planning models were updated to include:

- the NPP capital and operating cost parameters discussed above,
- current estimates for gas fired combined cycle plant capital and operating costs, and
- current natural gas price forecasts

The current gas price forecast is discussed in appendix C. The forecast is based on the assumption that the price of gas in Armenia will rise to at least 80 percent of the European price by 2015 and that gas prices will continue to escalate at 2.37 percent per year.

The LCGP system planning model assigns generators to meet system load in order of operating cost (i.e., fuel and O&M) to determine the lowest cost for generation to meet load demand in each year. When the 1,000 MWe NPP was placed into the model in 2017, the model selects it as one of the lowest cost generators. The model calculates the total cost for generation from all sources to meet the system load each year.

The results of the system planning model for the year 2017 are shown in figure 6.2. The case of no NPP assumes that two 500 MWe combined cycle plants are built instead of the new NPP. While the average cost of generation is significantly affected by the WACC for the new NPP, the cost of the combined cycle plants alternative is higher than any of the NPP ownership scenarios. This difference increases in future years as the price for gas continues to escalate while the costs for the NPP remain fairly constant.

The fifth case shown in figure 6.2 represents the effects of export of excess capacity of the new NPP. As discussed in IPS section 3, there is already an agreement with Iran to exchange 3 kWh of electricity for 1 cubic meter of gas. If the gas received from the swap of the excess NPP capacity is used to fuel the thermal power plants in the system, the effect would be to lower the average generating cost of the system significantly.

Figure 6.3 presents the trend in the average system wholesale generation tariff beginning when the new NPP begins operating. In this graph, it is assumed the NPP is owned under the public private partnership. It can be seen, that for the case of no NPP, the tariff will continue to escalate with the price of fuel. For the NPP case, the tariff remains fairly stable. If the value of gas received for the NPP excess capacity is considered, the cost for meeting Armenia’s generation requirements, will actually decrease, as the gas price increases.

Figure 6.2, System Generation Costs in 2017 for Different NPP Scenarios

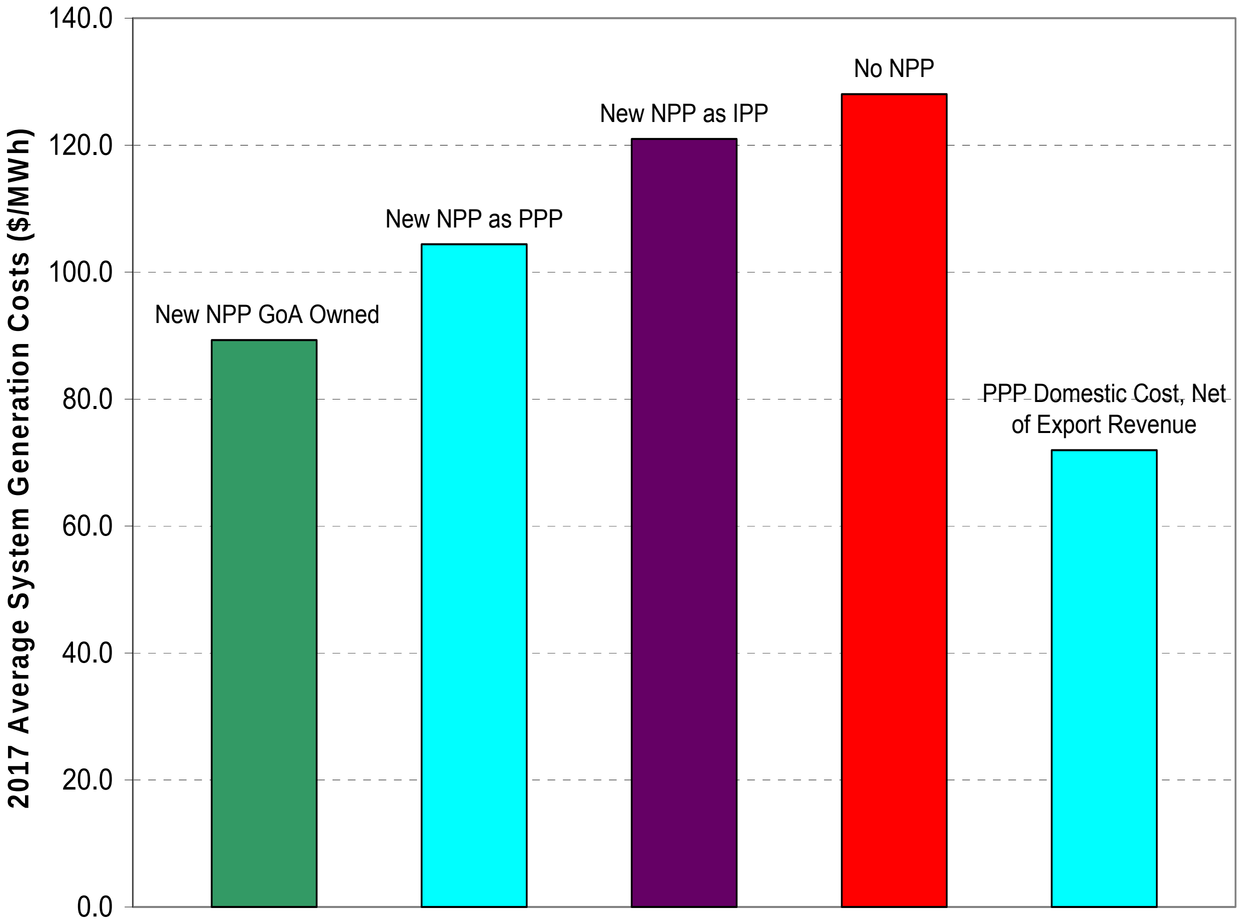
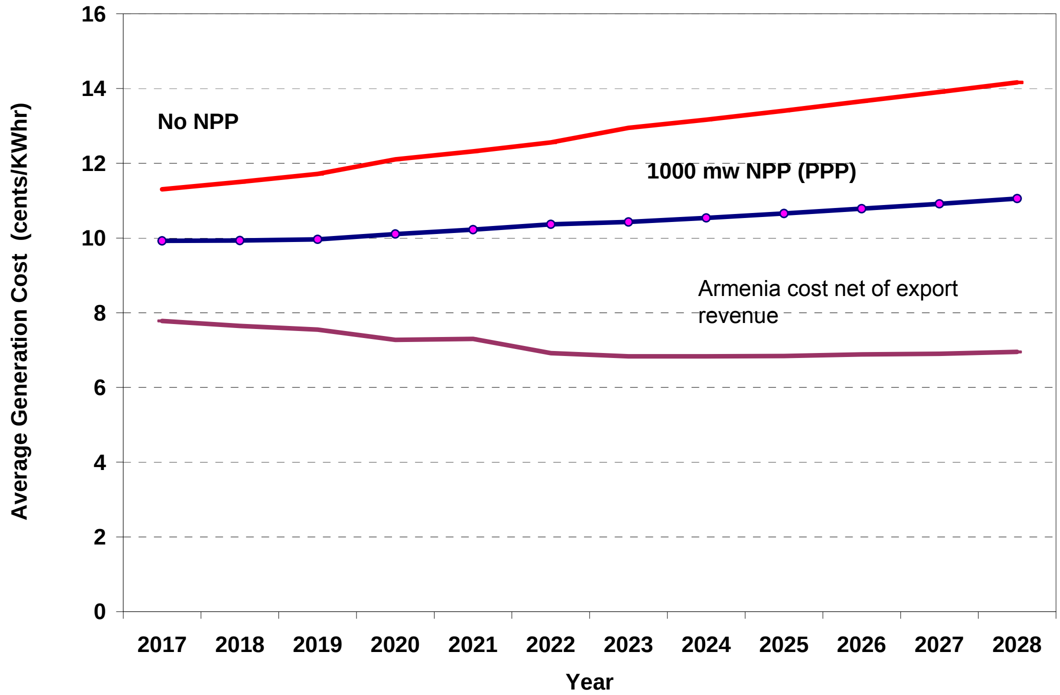


Figure 6.3, Average System Generation Tariff Trend



7. REVIEW OF ARMENIA'S NUCLEAR SAFETY POLICES AND REGULATORY CAPABILITY

Given the interest in the new reactor, Armenia needs to review the existing system of regulation and to bring it into harmony with western practice in preparation for the new reactor project development. The new regulatory framework will be needed as a basis for any potential tendering process. Additionally, ANRA will need to have sufficient staff with the necessary skills to oversee the licensing, construction, and operation of the new nuclear unit.

This study was prepared by the Nuclear and Radiation Safety Center and Advanced Systems and Technology Management, Inc. for Armenian Nuclear Regulatory Authority under the US NRC assistance program for regulatory strengthening in Armenia. The study produced to reports, which are described in the following sections. The reports are currently under review by ANRA.

7.1 ACTION PLAN FOR UPDATING THE REGULATORY PROGRAM FOR OVERSIGHT OF NUCLEAR POWER REACTORS IN ARMENIA

The regulation of the existing ANPP would continue the basis of Russian (RF) regulatory documents that have been accepted in Armenia. However, the lack of an interrelated frame of the national nuclear regulation will create problems with regulation of a new NPP. Such situation also contradicts the IAEA requirements

The Action Plan describes the overall strategy of ANRA to modify existing or develop new processes and requirements. The Action Plan was developed based on review of international practice and experience with various regulatory models and determination of the model that is most appropriate for Armenia. The Action Plan identifies the major regulations, and guidance documents on licensing processes, information submittals, and guidelines that need to be developed for the new reactor program in order to meet Armenia's international obligations under various conventions.

7.1.1 Regulations

The Action Plan describes new regulations to be prepared by ANRA in preparation for new plant licensing. The four recommended areas of regulations are Site Requirements, Design Requirements, Operational Requirements, and Decommissioning Requirements.

The Regulation on Site Requirements is urgently needed to confirm the selection of the ANPP site for the new nuclear unit and to complete the EIA process. This regulation will provide requirements and criteria for the site selection of nuclear installations. The regulation will require an evaluation of the level of risk related to geological, hydrological, meteorological, man induced and seismic hazard factors. Numerical criteria shall be assigned to all hazard classes. The Site Requirements for the evaluation of potential transfer of radiation through air and water will specify criteria for defining emergency planning area size and requirements for the evaluation of barriers for a potential evacuation

The Regulation on Design Requirements is also urgent in that it is needed to finalize the bid specifications for the tender process. This regulation will provide the basic technical requirements for nuclear power reactors, including general requirements for designing safety systems, structures and components and requirements for safety analyses.

7.1.2 Guidance

The Action Plan describes several sets of guidance documents to be prepared. The

The Guidance on Regulatory Processes will contribute to the applicant's understanding of the laws and regulatory requirements. Well-defined regulatory processes enable improvement of regulatory efficiency, providing that regulatory body and regulated community are aware of what should they expect from each other, and in what time. It is recommended to develop a set of documents, which describe regulatory processes to be implemented at the six stages of the lifecycle:

- Site selection process
- Construction licensing process
- Construction oversight
- Licensing for operation
- Operation oversight
- Decommissioning process

The Guidance on Information Submittal Requirements describes the format and content of information to be submitted during the regulatory processes. The guidance covers the Safety Analysis Report, the Comprehensive Safety Assessment, operational reports, and the Final Decommissioning Plan.

The Technical Guidelines are the documents which describe acceptable ways for applicants or licensees to meet requirements of regulations, but they do not contain binding requirements. Technical Guidelines will have references to the existing guides, codes and standards, developed by the engineering community in specific areas, including those issued by IAEA and in other countries with advanced regulatory programs. The ANRA guidance shall take into account codes and standards of the country which supplies the installation, or the country which manufactures the major equipment.

7.2 STAFFING, TRAINING AND TECHNICAL SUPPORT FOR UPGRADING OF A NUCLEAR SAFETY REGULATORY PROGRAM IN ARMENIA

In implementation of a nuclear power program, the important task is to provide the regulatory body with the staffing and technical support to contribute to the fulfillment of safety functions for the design, construction and operation of reactors. ANRA has a limited number of staff members with relevant knowledge and training for successful implementation of the regulatory program. Approaches to the staffing of regulatory body and to providing it with technical support are reviewed in this document.

The document provides recommendations for the roles of the regulatory body, the technical support organization, and international organizations. It also provides recommendations for staffing of regulatory body and for training of regulatory staff.

8. INTERNATIONAL AGREEMENTS AND CONTRACTS

The objective of this study is to determine whether there is a need for additional, or changes to existing, international agreements and contracts related to the new NPP project.

8.1 INTERNATIONAL AGREEMENT AND CONTRACTS COMMONLY ADOPTED BY COUNTRIES WITH NUCLEAR POWER PROGRAMS

This section describes the various different types of commonly adopted international agreements and contracts related to nuclear power programs. IAEA-TECHDOC-1259, *Nuclear Power Program Planning: An integrated Approach* lists the following commonly adopted agreements and contracts. The corresponding Armenian agreements and contracts are listed immediately below each numbered entry.

8.1.1 United Nations Nuclear Nonproliferation Treaty

The United Nations Nuclear Nonproliferation Treaty originally entered into force in 1970. The objectives of the Treaty are: 1) preventing the proliferation of nuclear weapons; 2) pursuing nuclear disarmament; and 3) promoting the peaceful uses of nuclear energy. The NPT has made it obligatory for all its non-nuclear weapon State parties to submit all nuclear material activities to IAEA safeguards inspections to verify peaceful uses of the material and technology(see item 3. below).

- Armenia adopted the Treaty on the Non-Proliferation of Nuclear Weapons on 24.09.1991

8.1.2 Regional or Bilateral Nuclear Nonproliferation Treaties or Safeguards Agreements

Bilateral nuclear nonproliferation treaties and agreements are entered into by counties receiving or transferring nuclear technology or equipment for peaceful applications. Such treaties would normally require verification of compliance with safeguards agreements by IAEA (see item 3. below).

- Agreement between Armenia and Government of Russia on Cooperation in area of Peaceful Use of nuclear Energy (25.09.00, Moscow)
- Governmental Decree on Approval of CIS Countries Agreement on Creation of Universal Database in area of Peaceful Use of Nuclear Energy (01.06.02)

8.1.3 Safeguards Agreement with IAEA

Safeguards agreements are activities by which the IAEA can verify that a State is living up to its international commitments not to use nuclear programs for nuclear-weapons purposes. The global Nuclear Non-Proliferation Treaty (NPT) and other treaties against the spread of nuclear weapons entrust the IAEA as the nuclear inspectorate. Today, the IAEA safeguards nuclear material and activities under agreements with more than 140 States.

- Agreement between the Republic Armenia and the International Atomic Energy Agency for the Application of Safeguards in connection with the Treaty on the Non-Proliferation of Nuclear Weapons (23.09.1993).

- GoA Decree No. 1597, Protocol Additional to the Agreement between the Republic of Armenia and the International Atomic Energy Agency for "The Application of Safeguards in connection with Treaty on the Non-Proliferation of Nuclear Weapons" (28.06.2004)

8.1.4 Bilateral Co-operation and Supply Agreements

Bilateral Co-operation agreements are entered into by countries exchanging nuclear equipment or technology needed for the development of peaceful uses of nuclear technology. Such agreements would normally require verification of compliance with safeguards agreements by IAEA. An organization called the Nuclear Supplies Group (NSG) works in concert with IAEA in the development of non-proliferation programs and guidelines.[59] Bilateral co-operation agreements generally follow NSG guidelines.

Armenia already has a bilateral co-operation agreement with the Government of Russia on cooperation in area of peaceful use of nuclear energy.

In order to receive nuclear power plant technology from US suppliers, Armenia must enter into an agreement for cooperation as described in the US Atomic Energy Act, Section 123 (the 123 Agreement). The 123 Agreement includes the following requirements:

- that IAEA safeguards be maintained on nuclear materials and equipment
- guaranty that nuclear material will not be used for any nuclear explosive device
- guaranty that material and data will not be transferred
- guaranty that adequate physical security will be maintained

Export of nuclear power plant technology from Canadian suppliers must be approved by the Canadian Nuclear Safety Commission (CNSC), which controls the import and export of nuclear materials and other prescribed substances, equipment and technology. Canada has undertaken nuclear cooperation only with those states that have signed a Nuclear Cooperation Agreement (NCA) with Canada. The NCA contains several assurances including:

- A non-explosive use commitment;
- A provision for fall-back safeguards;
- Retransfer, enrichment and reprocessing controls; and,
- Assurance of adequate physical protection measures.

Since 1976 Canada has engaged in nuclear cooperation only with states that have ratified the Treaty on the Non-Proliferation of Nuclear Weapons (NPT) or have taken an equivalent binding step and accepted International Atomic Energy Agency (IAEA) safeguards on the full scope of their nuclear activities.

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[59]. The history and activities of the NSG are described in IAEA INFCIR/539/Rev3. The full text of this Circular is available at: http://www.nsg-online.org/PDF/infcirc539r3.pdf

In addition to bilateral agreements on nuclear cooperation with suppliers, agreements are likely to be required for access to transboundary or common resources. These agreements would include:

- Electric power export agreements
- Transboundary agreements for transportation of NPP equipment
- Transboundary shipping agreements for transportation of spent nuclear fuel for disposal.

8.1.5 Third Party Nuclear Liability Conventions

Many different protocols have been adopted by different counties and many counties have not adopted any particular protocol or have developed their own versions of 3rd party liability indemnification. However, In the current environment of international markets and financing for nuclear equipment and facilities, countries building new nuclear power plants have increasingly found it necessary to update and increase the limits and coverage of their 3rd party liability protection.

Following is a brief summary of the principle different conventions in use today. A more detailed discussion of these and other conventions is provided in the references [60,61] below.

a. The Paris Convention of 1960 was the earliest convention and was developed by the OECD NEA. It was developed primarily for use by Western European countries. Like most 3rd party liability conventions of its time (including the Vienna Convention b. below), it is only applicable when both parties to an event have adopted the convention.

b. The 1963 Vienna Convention, adopted by Armenia in 1993, is the second of the two earliest conventions developed and requires only approximately US$ 5 million minimum of 3rd party liability protection. However, individual countries adopting the convention can set higher limits of protection at their own initiative. This convention was developed for worldwide adoption.

c. The “Joint Protocol” of 1988 (which entered into force in 1992) was designed to fill the gap in protection when both parties to an event were not covered by the same convention. Under this protocol, adoption of either the Paris or Vienna conventions provided the same coverage as if the parties were covered by both conventions.

d. The Convention on Supplementary Compensation for Nuclear Damage (CSC) was adopted by the International Atomic Energy Agency (IAEA) in 1997. The object of the CSC is to bind together, through a system of contributions (initial and supplementary), countries with strong nuclear programs into a pool to share liability and distribute the economic burden between member states in the event of

[60] A comprehensive discussion of the history of Third Party Liability Conventions and the status of these conventions is provided in a paper by Omer F. Brown II, “Nuclear Liability: A Continuing Impediment To Nuclear Commerce”, The Uranium Institute 24th Annual Symposium 8-1-September 1999: London. The full text of this paper is available at: http://world-nuclear.org/sym/1999/pdfs/brown.pdf

[61] A comprehensive discussion of issues related to the selection of a 3rd Party Nuclear Liability Convention is provided in “NEA Issue Brief 4: International Nuclear 3rd Party Liability” The full text of this issue brief is available at: http://www.nea.fr/html/brief/brief-04.html

a nuclear accident. In an era of increasing globalization it seems likely that this approach will gain increasing favor as the ultimate resolution of the nuclear liability issue. The CSC amended the 1963 Vienna Convention to set the limit of the operator's liability at not less than about $ 400 million. The Protocol also broadens the definition of nuclear damage (now also addressing the concept of environmental damage and preventive measures), extends the geographical scope of the Convention, and extends the period during which claims may be brought for loss of life and personal injury

Armenia has signed the 1963 Vienna Convention but has not committed to the more recent conventions or protocols discussed above. Nuclear suppliers, constructors, and financial organizations will not do business in a country that has not agreed to the CSC protocol or established equivalent national legislation.

8.1.6 Convention on Early Notification of a Nuclear Accident

Developed in 1986 following the Chernobyl nuclear plant accident, this Convention establishes a notification system for nuclear accidents which have the potential for an international transboundary release that could be of radiological safety significance for another State. It requires States to report an accident's time, location, radiation releases, and other data essential for assessing the situation. Armenia has adopted this convention

8.1.7 Convention on Assistance in the Case of a Nuclear Accident or Radiological Emergency

This Convention sets out an international framework for co-operation among States Parties and with the IAEA to facilitate prompt assistance and support in the event of nuclear accidents or radiological emergencies. It requires States to notify the IAEA of their available experts, equipment, and other materials for providing assistance. Armenia has adopted this convention.

8.1.8 Convention on Physical Protection of Nuclear Material

This convention is legally binding for adopting States to protect nuclear facilities and material in peaceful domestic use, storage and transport. It also provides for cooperation between and among States regarding rapid measures to locate and recover stolen or smuggled nuclear material, mitigate any radiological consequences of sabotage, and prevent and combat related offences. Armenia has adopted this convention.

8.1.9 Convention on Nuclear Safety

The objective of this Convention is to legally commit participating States operating land-based nuclear power plants to maintain a high level of safety by setting international benchmarks to which states would subscribe. The obligations of the Parties are based to a large extent on the principles contained in the IAEA Safety Fundamentals document "The Safety of Nuclear Installations". These obligations primarily cover sitting, design, construction, operation, the availability of adequate financial and human resources, the assessment and verification of safety, quality assurance and emergency preparedness. As such, this is a very import statement by the international nuclear community on nuclear safety. Armenia adopted the Convention on Nuclear Safety on 24.09.1997 and filed the required report detailing compliance with the Convention in September 2007

8.2 ADDITIONAL ARMENIA INTERNATIONAL AGREEMENTS AND CONTRACTS IN THE PROCESS OF BEING DRAFTED AND ADOPTED

This section discusses the status of International Agreements currently under consideration by GoA.

8.2.1 Joint Convention on the Safety of Spent Fuel and Radioactive Waste Management

This convention applies to spent fuel and radioactive waste resulting from civilian nuclear reactors and to spent fuel and radioactive waste from military or defense programs if and when such materials are transferred permanently to, and managed within exclusively civilian programs, or when declared as spent fuel or radioactive waste for the purpose of this convention by the Contracting Party. The convention also applies to planned and controlled releases into the environment of liquid or gaseous radioactive materials from regulated nuclear facilities. A resolution to adopt the Joint Convention on Safety of Spent Fuel Management and Safety of Radioactive Waste Management has been drafted but not yet ratified.

8.2.2 Bilateral Co-operation Agreements

These types of agreements are interred into by countries agreeing on access to transboundary or common resources.

A resolution to adopt the Convention on Protection and Use of Transboundary Watercourses and International Lakes has been drafted but not yet ratified.

Armenia has a bilateral co-operation agreement with the Government of Russia on cooperation in area of peaceful use of nuclear energy. Similar bilateral cooperation agreements with other candidate suppliers, such as the US and Canada, have not been established.

8.2.3 Global Nuclear Energy Partnership

The Global Nuclear Energy Partnership (GNEP) is a voluntary international partnership of nations with interest in nuclear power. The objective of the GNEP is to bring about a significant expansion in nuclear power worldwide while responsibly managing nuclear waste and reducing proliferation risks. GNEP has over 20 partner nations including the US, the Russian Federation, Japan, and Canada. The GNEP program includes research and technology development programs as well as international policy collaboration. GNEP sponsors working groups on Reliable Fuel Services and Nuclear Infrastructure as well as other research in advanced reactors and spent fuel recycling and disposal.

In July 2008, Armenia was invited to join the GNEP as a partner. That invitation is under consideration by the GoA. Participation in GNEP would provide significant benefits to Armenia's nuclear program. The benefits would include participation in and access to results of research programs and access to the fuel cycle services to be deployed in the future.

8.3 CONCLUSION AND RECOMMENDATIONS

The Armenia system of international agreements and treaties has undergone a significant update in the post Soviet era. As a result of the update, this important element of the Armenian nuclear program is now generally consistent with commonly accepted international practice.

Following is a discussion of three areas where further updating should be considered and the ongoing development of new requirements should be expeditiously completed to support the new NPP.

8.3.1 Third Party Nuclear Liability Conventions

Armenia should adopt the CSC convention in order to have full access to international nuclear commerce. Armenia has signed the 1963 Vienna Convention but has not committed to the more recent conventions or protocols discussed above. A new nuclear project involving Western suppliers and financing will require Armenia to commit to the terms of the CSC and to obtain liability insurance to the limits of the protocol. The minimum liability limits of approximately $5 million originally established under the 1963 Vienna Convention are far below what would be expected today.

8.3.2 Completion of Drafts of New Documents Adopting Additional Conventions

The following drafts of two documents to adopt additional conventions have been completed but not yet ratified by Armenia. These conventions are applicable to the new NPP and the ratification process should be completed expeditiously.

- The Joint Convention on Safety of Spent Fuel Management and Safety of Radioactive Waste Management.
- Convention on Protection and Use of Transboundary Watercourses and International Lakes.

8.3.3 Bilateral Co-operation Agreements

Armenia should establish nuclear cooperation agreements with the governments of candidate suppliers of nuclear technology, in order to have full access to the information needed to make informed decisions on supply agreements. These agreements would include the “123 Agreement” with the US and the Nuclear Cooperation Agreement with Canada.

8.3.4 Bilateral Shipping Agreements with Neighbor States

Armenia will need to establish agreements to ensure the unimpeded transportation of equipment for the new nuclear plant through neighboring states. When the arrangements for disposal of spent nuclear are established, additional agreements and licenses for shipment of spent fuel through a neighbor state will need to be established.

9. ASSESSMENT OF HUMAN RESOURCE DEVELOPMENT NEEDS

The development and use of nuclear power technology requires adequate human resources and knowledge. While Armenia has a workforce experienced in operation and regulation of a nuclear power plant (NPP), a significant portion of the current ANPP workforce is approaching retirement age and will not be available for the new plant. An assessment of the Human Resource Development Needs for the new nuclear unit project has been conducted by the staff of the MoENR with support of IAEA experts under an IAEA tailored collaboration project, ARM005.

A functional task analysis approach has been used to identify the tasks and competencies needed for each phase of the NPP project: Initial Planning, Preparation, Construction, Commissioning, and Operation. From these analyses, the staffing requirements for each phase have been developed.

The study has also performed surveys of human resources in existing engineering organizations in Armenia (e.g., ANPP, CJSC Atomservice, CJSC Armatom, CJSC Technoatomenergo, Nuclear and Radiation Safety Scientific Technical Center). The survey identified the skills, age, and experience levels of all employees in the subject organizations.

The study has also conducted surveys of technical training institutions in Armenia. These institutions include universities (e.g., State Engineering University of Armenia, Yerevan State University, Yerevan State University of Architecture and Construction) as well as technical training schools with related curriculum.

The results of this study will include recommendations for human resource development and training. A follow on study with IAEA support is planned for calendar year 2009.

10. LEGAL AND LEGISLATIVE REQUIREMENTS

All requirements related to nuclear activities must be defined by laws and provisions for enforcement of these requirements must be clearly established.

The objective of this study is to evaluate the need for new or revised legal and legislative requirements related to the Armenian Nuclear Power Program to bring it into conformance with commonly accepted international practice. The scope of this study (e.g. NPP private ownership and/or operation, nuclear liability indemnification, and licensing fees) is limited to requirements **not** directly related to technical safety considerations. Legal and legislative requirements related to technical safety requirements are discussed in Chapter 7.

10.1 LEGAL AND LEGISLATIVE REQUIREMENTS COMMONLY ADOPTED BY COUNTRIES WITH NUCLEAR POWER PROGRAMS

The IAEA Handbook on Nuclear Law[62] describes what it refers to as "the normal legal hierarchy applicable in most States" with nuclear programs. The handbook further states, "This hierarchy consists of several levels. The first, usually referred to as the *constitutional level*, establishes the basic institutional and legal structure governing all relationships in the State. Immediately below the constitutional level is the *statutory level*, at which specific laws are enacted by a parliament in order to establish other necessary bodies and to adopt measures relating to the broad range of activities affecting national interests. The third level comprises regulations which are detailed and often highly technical rules to control or regulate activities specified by statutory instruments ....." [63]

Sections 10.1.1 and 10.1.2 below list and briefly describe the various different commonly adopted legal and legislative requirements for the second two levels: 1) the Statutory Level, referred to as Laws and 2) the Regulatory Level referred to as Regulations. The international consensus document, IAEA Handbook on Nuclear Law 2003 and the US Nuclear Power Regulatory Program with many reactors years of experience were the primary references used to develop the lists provided Sections 10.1.1 and 10.1.2. The corresponding existing Armenian legal and legislative documents are listed immediately below each numbered entry in these sections. A summary of general conclusions and specific recommendations for revisions to existing Armenian requirements, or additional new requirements, is provided in Section 10.3.

10.1.1 Statutory Requirements (Laws)

Law on Nuclear Power Applicable to the New NPP

The new general Law on nuclear power currently being drafted for Armenia fits within the statutory level. This new Law is important because it will be the foundation for the detailed technical requirements (addressed in IPS Chapter 7) and the less technical legal and

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[62] IAEA Handbook on Nuclear Law
www.pub.iaea.org/MTCD/publications/PDF/Pub1160_web.pdf

[63] An example of a comprehensive plan to develop a legal and legislative framework for a modern nuclear power program consistent with accepted international practice is provided in a "white paper" titled, Policy of the United Arab Emirates on the Evaluation and Potential Development of Peaceful Nuclear Energy
http://www.carnegieendowment.org/static/npp/reports/UAE_white_paper.pdf

legislative requirements addressed in this chapter. Examples of requirements that should be addressed in the new Law include:

- Designation of a government body below the Parliamentarian level to assume the responsibility/authority for developing and promulgating detailed regulations/requirements for implementing the individual provisions of the new Law and proposing additional commonly adopted international treaties and contracts related to nuclear safety for ratification (see footnote 3 below). This may be a new approach to establishing detailed regulatory requirements in Armenia; however, it is consistent with common practice in many countries and likely to be most familiar to western suppliers and sources of financing for the new NPP. Also the IAEA Handbook on Nuclear Law refers to it as “the normal legal hierarchy applicable in most States with nuclear programs”.
- A requirement for adoption of commonly accepted international practices for licensing, design, construction, operations, and decommissioning (with exceptions and conditions appropriate for Armenia). The objective is to clearly establish Armenia’s intention to operate its’ nuclear power program in a manner consistent with international norms and standards
- Ownership and operational control of the New NPP.
- Ownership, storage, and disposal of radioactive waste and spent fuel
- Funding of regulatory activities
- Decommissioning funding

10.1.2 Regulatory Requirements (Regulations)

Detailed technical and administrative requirements must be established for the effective regulation of a nuclear power program. As stated above, detailed technical safety requirements are outside the scope of this IPS Topic but are included in Topic 7.

The IAEA Handbook on Nuclear Law is divided into 5 Parts with a total of 14 Chapters, each with various sections and subsections. Only Chapters 1, 2, 3, 11 and 13 address legal or legislative requirements within the scope of this study. Each of these chapters is discussed separately below followed by a separate discussion of several additional requirements derived from the USNRC regulatory program. The requirements (Regulations) discussed here are those normally developed and enforced by the National Nuclear Regulatory Authority under the power granted by the legislative branch of the national government. However, some national customs may dictate that at least some of these types of requirements be established as acts of the legislature.

1. **Chapter 1, subsection 1.4.7 - Sustainable Development Principle**, establishes environmental protection as one of the principle elements of nuclear law. US CFR Title 10 Part 51 App. A also contains requirements for environmental protection assessments.

   <u>Corresponding Armenian Requirements</u>

   - Law of the Republic of Armenia on Environmental Impact Assessment as of 20.11.1995

   - GoA Decree № 609-N as of 12.05. 2005 on approval of the licensing procedure and license form for site selection of nuclear installations.

   The only document available for the second requirement listed above was GoA Decree 609 (04.06.2003) for general land use requirements, not 609-N specifically for nuclear installations.

2. **Chapters 2 and 3 - General types of Organizational and Administrative Requirements,** similar to those in US CFR Title 10 Part 2 (e.g. the organization, independence and authorities of the regulatory body, provisions for public information and participation in licensing and other regulatory activities, suspension, modification or revocation of a license, inspection and enforcement, etc.).

   Corresponding Armenian Requirements

   ANRA provided assurances that this block of requirements is fully developed, including approximately 35 Decrees approved by the Government.

3. **Chapter 11 - Nuclear Liability and Coverage**, establishes legal and legislative requirements in the area of 3rd party liability associated with nuclear activities. This subject is also addressed in US CFR Title 10 Part140.

   Corresponding Armenian Requirements

   - 1963 Vienna Convention on Civil Liability for Nuclear Damage (22.06.1993) (see Section 10.3 Recommendation 4.)

4. **Chapter 13 - Import and Export Controls**, establishes legislative requirements which are similar to those in US CFR Title 10 Part110 prescribing licensing and enforcement, procedures and criteria for the export and import of nuclear equipment and material. This part also gives notice to all persons who knowingly provide to any licensee, applicant, contractor, or subcontractor, components, equipment, materials, or other goods or services, that relate to a licensee's or applicant's activities subject to this part, that they may be individually subject to NRC enforcement action.

   Corresponding Armenian Requirements

   - GoA Decree № 1597-N as of 26.10.2004 on fulfillment of obligations undertaken under the Protocol Additional to the Agreement between the Republic of Armenia and the International Atomic Energy Agency for "The Application of Safeguards in Connection with Treaty on the Non-Proliferation of Nuclear Weapons.

   - GoA Decree № 1790-N as of 09.12. 2004 on approval of the licensing procedure, license and application form for import and export of radioactive materials, devices containing radioactive materials, or radiation generators.

   These two requirements are related to the area of Non-Proliferation of Nuclear Weapons but they do not include specific controls to prevent import or export of material or equipment that could support proliferation of nuclear weapons. The first Decree relates only to GoA inventory reporting requirements in the Non-proliferation Treaty and the second decree is focused primarily on radiation safety controls on imports and exports of “radioactive materials, equipment containing radioactive material and ionizing generators”. Both of these decrees do refer to other requirements which may be more specifically related non-proliferation.

Additional Commonly Adopted Requirements Derived From US CFR Title 10

5. **US CFR Title 10 Part 13 - Program Fraud Civil Remedies**, This part (1) establishes administrative procedures for imposing civil penalties and assessments against persons who make, submit, or present, or cause to be made, submitted, or presented, false, fictitious, or fraudulent claims or written statements to authorities or

to their agents, and (2) specifies the hearing and appeal rights of persons subject to allegations of liability for such penalties and assessments.

Corresponding Armenian Requirements

This is a very important area that needs to be covered by legal requirements within the nuclear regulatory system to impose penalties for making false statements to the regulator. The Armenian Code on Administrative Misdemeanors contains several Articles providing penalties for (a) officials (government servants) making operational team to violate operational rules of nuclear installations and radioactive waste storage; (b) hindering lawful activities of nuclear installations and radioactive waste storage staff and officials; (c) withholding or distorting of information on nuclear or radioactive accidents. Along with that a penalty is provided by the RoA Criminal Code for violation of rules on the nuclear energy objects (installations).

6. US CFR Title 10 Part 21 - Reporting of Defects and Noncompliance, This part requires "any individual director or responsible officer of a firm constructing, owning, operating or supplying the components" of any nuclear facility or activity who obtains information reasonably indicating:

That the facility, activity or basic component supplied to such facility or activity fails to comply with applicable rule, regulation, order, or license of the Commission relating to substantial safety hazards or that the facility, activity, or basic component supplied to such facility or activity contains defects, which could create a substantial safety hazard, to immediately notify the Commission.

Corresponding Armenian Requirements

To date no such Armenian requirements have been identified that can be referenced in the IPS.

7. U.S. Nuclear Regulatory Commission Enforcement Policy Statement, This policy statement describes the enforcement policy and procedures that the NRC and its staff follow in initiating and reviewing enforcement actions in response to violations of NRC requirements.[64]

Corresponding Armenian Requirements

To date no such Armenian requirements have been identified that can be referenced in the IPS.

8. US CFR Title 10 Part 170 & 171 – Licensing Fees, These parts set out fees charged for initial services rendered by the Nuclear Regulatory Commission and provisions regarding their payment.

Corresponding Armenian Requirements

Currently, the budget for the Armenia's nuclear regulating authority is provided by government revenues. In the situation where the new nuclear unit is owned by and

[64] The full text of this Policy Statement can be accessed at: http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html

investor rather than the government, there would be benefits to having the Regulatory budget provided at least in part by fees from the licensee.

10.2 SUMMARY OF GENERAL CONCLUSIONS AND SPECIFIC RECOMMENDATIONS FOR ADDITIONAL OR REVISED ARMENIAN LEGAL AND LEGISLATIVE REQUIREMENTS

1. Radioactive Waste

There are currently no laws or policies that define the responsibilities of the government and private parties with respect to radioactive waste. Particularly for the case of the new nuclear project owner by investors rather than the government, these responsibilities should be defined in law or in a government policy statement.

Recommendation 1

A new law or other legal instrument should be enacted to identify responsibilities for management of spent fuel and other radioactive wastes resulting from NPP operation and decommissioning. The law should include specific conditions for transfer of the waste from the NPP owner to the government.

2. 10.1.2 Item 1: Sustainable Development Principle (Environmental Protection)

As stated in Section 10.1.2 ITEM 1 above, the only document available for the second requirement listed above was GoA Decree 609 (04.06.2003) for general land use requirements, not 609-N specifically for nuclear installations.

However, a copy of the document for the first unnumbered requirement was available and looked as if it might be a draft of a proposed new law that would be directly applicable to nuclear installations. This document is a comprehensive statement of requirements for environmental protection assessments that can be considered consistent with accepted practice.

Recommendation 2

The unnumbered draft provided should be reviewed and if it is found to be the intended Decree applicable for nuclear installations it should be adopted and numbered accordingly.

3. 10.1.2 Item 3: Nuclear 3rd Party Liability Coverage

This requirement is very important for Armenia. The liability limits in the 1963 Vienna Convention on Civil Liability for Nuclear Damage (22.06.1993) currently adopted by Armenia provides liability limits far below what is considered acceptable today. If these limits are not increased, access to western suppliers and financing will likely be very limited. Two of the major US reactor vendors have indicated that, “no US supplier would supply to a nation that did not accede to the CSC”. A complete summary of the various commonly adopted 3rd party liability conventions available today (including the CSC) is provided in IPS Topic 8.

Recommendation 3

Given the increasing reliance on the CSC as the standard for 3rd party liability protection, Armenia should consider adopting the CSC in order to have the broadest possible access to nuclear equipment suppliers and financing.

4. 10.1.2. Item 4. Import and Export Controls

As stated in section 10.1.2. Item 4. above, the two requirements referenced do not provide Import/Export controls directly related to Non-Proliferation of Nuclear weapons. Instead they are focused on inventory reporting requirements and radiation safety during shipping.

Recommendation 4

The Section 10.1.2 Item 4 references to other existing requirements should be reviewed to determine if they included requirements more directly related to non-proliferation controls. All of the non-proliferation controls should be consolidated in a single document (e.g. Decree) but if this is not possible specific cross references to other non-proliferation controls should be made in each of the related documents.

5. 10.1.2 Item 5. Program Fraud Civil Remedies

This requirement is based on the same premise as Recommendation 7 below i.e. safety concerns must not be hidden or ignored and that if this occurs penalties will be imposed on individuals and/or organizations.

Recommendation 5

A requirement imposing civil remedies for material false statements to regulatory officials should be established as part of the nuclear regulatory system.

6. 10.1.2 Item 6. Reporting of Defects and Noncompliance

The highly technical nature of nuclear technology and large number of individuals working at these such facilities makes it likely that these individuals will become aware of some safety issues that have not yet been discovered by regulatory officials. Therefore, it is imperative that these individuals report these safety issues as soon as they are discovered.

Recommendation 6

A requirement to report safety issues as soon as they are identified by any individual having such knowledge should be established as part of the nuclear regulatory system.

7. 10.1.2 Item 7. Regulatory Enforcement Policy

Consistency and coherence in the enforcement of regulatory requirements is important to assuring effective regulation. Individuals and organizations need to understand that they will be held accountable for their actions or inactions as well as understanding the process that will be used to assure this accountability.

Recommendation 7

A Regulatory Enforcement Policy should be established and documented as part of the overall nuclear regulatory system in Armenia.

11. REVIEW OF ARMENIA ELECTRICITY TARIFFS AND SOCIAL SECURITY NET

The objective of this study is to review the impact on electricity tariffs and assess the needed funds for the Armenian social security net to ensure that rising tariffs will not unfairly disadvantage the low income sector of the population.

11.1 HISTORY OF ELECTRICAL TARIFFS IN ARMENIA

It has been the policy of the Government of Armenia (GoA), supported by International financial institutions, to reduce the burdens on vulnerable customers while implementing the strategy of restoring financial viability to the power sector. The power sector of Armenia has gone through several stages of economic restructuring over last decade. As part of that process, the level of tariffs has finally reached a level of full cost recovery.

Historically, retail electricity tariffs were set artificially low by the Government and were insufficient to cover operating costs. In December 1994, Armenergo (the integrated monopoly operating the Electric power sector of Armenia) implemented a single or unitary tariff for all customers. Exceptions included a special group of subsidized “privileged” residential customers (e.g., the poor, the elderly, generally disadvantaged and employees of some state institutions and power companies) who paid half price.

The Energy Law adopted on June 9, 1997 effectively prohibited subsidization through electricity tariffs. It requires that tariffs be based on full cost recovery principles, including reasonable returns on investment comprising both interest on debt and return on equity “sufficient to provide safe and efficient operation of the entities in the energy sector”. Discrimination in tariff setting was not permitted; all consumers with similar “delivery costs” were to be offered similar tariffs. The law permitted tariffs to be differentiated on the basis of quantity of use, time of use, season and type of service offering.

Resolution 52 dated November 11, 1998 established new consumer groups by voltage levels starting from January 1, 1999. As a result, tariff for end-use consumers using 0.38 kV networks was set at 25 Drams per kWh regardless of the volume of consumption per month.

11.2 THE SOCIAL SECURITY NET IN ARMENIA

In order to support the vulnerable population, the GoA adopted Decree № 727 dated November 19, 1998 “On the Introduction of the System of Family Benefit in the Republic of Armenia” (FBS). The Decree eliminated the previous system of benefits and compensations (subsidized tariffs and fees) by the establishment of a unified system of benefits. The overall goal was to implement the social assistance policy addressed to support poor families. By this decree, the GoA established procedures for allocation and payment of family benefits. The payments are made from the state budget only. The Decree firmly stated the family benefits entitlement, calculation and payment procedures, time periods, required documents and reasons for the termination of payment. Based on that decision, a system of poverty scoring was established to assess family eligibility for benefits. Each family was checked against certain criteria (such as number of working family members, total income, income per capita, disabled, etc) and appropriate points were assigned to each family that applied.

The decree currently in force is Decree № 2317-N dated January 30, 2006 “On Approval of the Procedures on Assessment of Family Poverty and the Personal Data Protection and Changes in Family Poverty Database System, Personal Data Exchange between the RoA Ministry of Labor and Social Affairs and Regional Agencies for Social Services”. The

Decree states the criteria, poverty scores, family poverty level assessment formula and required documentation to verify the mentioned information.

To assess the family poverty level the following characteristics are used:

- Social group for each family member,
- Number of employed family members,
    - Residence,
- Family housing conditions,
- Availability of personal car,
- Business activity,
- Real estate transactions,
- Custom duty payments for goods export and import by any family member,
- Electric energy consumption by family during summer months,
- Average monthly payments for international calls,
- Conclusions on family's social-economic conditions made by agency and the respective social assistance council, and,
- Family's income.

The social group refers to the level of disability of the person or his social status (such as students, orphans, etc). Each person in the family if it belongs to one of the defined social groups is given the score of that social group. The social group poverty scores are differentiated by the following categories:

- Disabled,
- Disabled children,
- Under-age children,
- Orphanage,
- Children without parental custody,
- Single-mother,
- Divorced parent children,
- Students,
- Pregnant,
- Unemployed,
- Pensioners,
- Single unemployed pensioner,
- Old pensioner, and,
- "Absent" family members.

The scores for each social group are defined by the decree and reflect the level of poverty of the person based on his physical or social conditions (the scores are higher for more needy). The decree also defines numeric coefficients for other characteristics, such as family housing conditions, availability of personal car, etc. After all information is collected on each family member and other characteristics of the family the special formula is used to calculate the final score of Overall Family Poverty Level (OFPL).

11.3 ALLOCATION AND PAYMENT PROCEDURES

GoA adopted Decree № 110-N "On the Approval of Allocation and Payment Procedures for the Family Benefit and Lump Sum Benefit" dated February 18, 2006, prescribes the allocation and payment procedures for family benefits and lump sum benefits (FBALSB). The payments of FBALSB are performed from the state budget of the RoA, through social service regional agencies. Every year, the GoA specifies the amount of financial resources available for the FBALSB, considering the number of low-income families, the family poverty threshold score, base amount of family benefit and additional amount paid to each under-age child of the family based on the procedure for assessment of the family's poverty level. To receive the benefit, the particular family registered in the system of low-income families must have a family poverty score above the threshold level. The payment is made starting from the month following the application month.

The family applies for family poverty benefit to regional social agencies presenting necessary documents to be registered in the appraisal system and, if the family appears to meet the eligibility criteria, an inspector pays a home visit to assess the claim's veracity on family's social-economic conditions. To register the family in the system or to make changes in the poverty score, the inspector creates a family social certificate in a Family Poverty Database System. Family members are obligated to report on any changes in their family status to the social agencies.

Decree № 110-N specifies in detail all items related to the allocation of benefits, such as: the application procedures, required documents, obligations of social service regional agency's employees, payment procedures, changes in the amount of benefit, termination of benefits, re-registration of families, procedures for allocation of immediate benefits, structure of payment lists and registration tables.

As the Poverty Family Benefit criteria are refined from year to year, the number of eligible consumers declined from 218,617 in 1999 to 146,726 in 2005.

	2001	**2002**	**2003**	**2004**	**2005**
Number of families covered by Poverty Family Benefit System	168,947	175,743	179,332	171,002	146,726
Amount of average monthly benefit per family, Drams	7,400	6,750	6,319	7,829	13,328

11.4 IMPACTS OF RISING TARIFFS

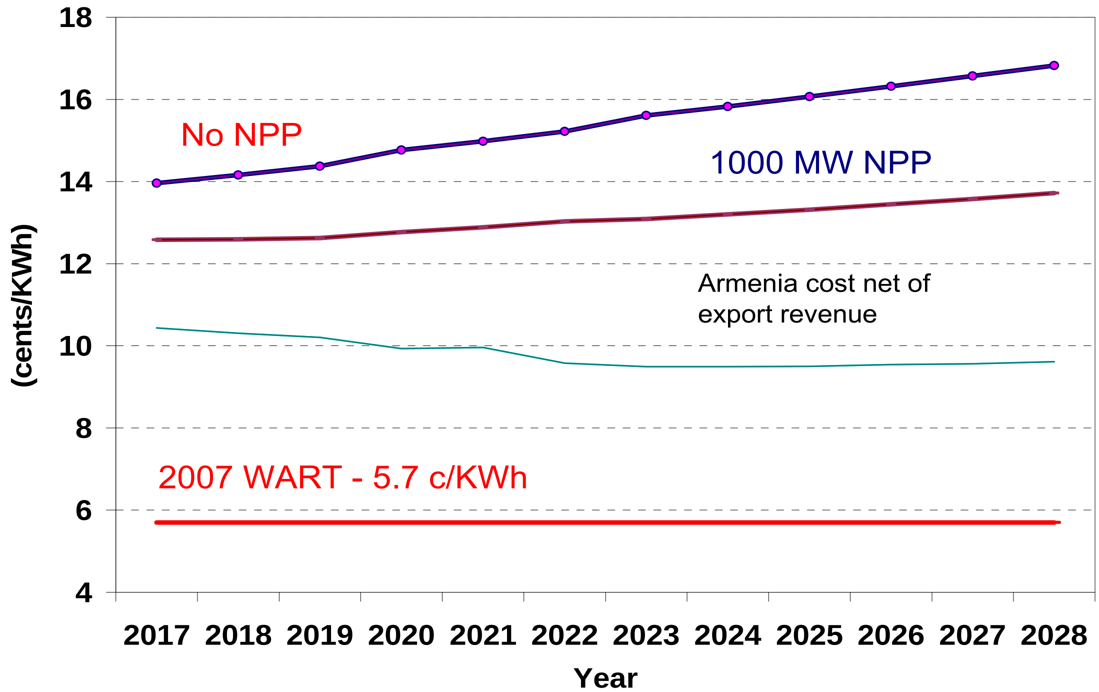
As described above, Armenia has quite robust social system providing support to needy families, including their needs to pay for electricity. However, the Government of Armenia must be prepared to respond through its support system to the new challenges looming as a result of major changes in the energy sector.

The era of low electricity and natural gas tariffs for Armenian customers is coming to an end. There are several driving factors, which will eventually result in significantly higher end-use tariffs:

- Need for replacement of the existing nuclear unit, which lifetime will expire in 2016;
- Expected transition to European prices for natural gas supplies to Armenia, which has been announced by the Russian Gasprom;
- Retirement of old and inefficient thermal units and need for construction of new ones.

The economic analysis demonstrates that the tariff impact on end-users will be significant regardless of the system expansion strategy implemented in Armenia. Moreover, the nuclear replacement scenario will have lesser impact than the scenario assuming replacement of the existing ANPP with new thermal units. The following graph shows the level of end-use tariffs expected in Armenia during the period from 2017 to 2028 for different generation expansion plans.

Weighted Average Retail Tariff (WART)



Such a drastic increase in end-user tariffs will affect all groups of consumers in Armenia, increasing financial burdens on industrial and commercial customers as well as on the population. Clearly, it will result in an economic adjustment requiring a more energy efficient and less energy intensive economy. However, the vulnerable customers, with their very low levels of electricity consumption will be affected the most, since there is little room for them to adjust through reduced consumption. The existing Low Income Family Support system must plan for increased support to low income families through higher budgeted amounts in the state budget.

The rate of poverty in 2006 was 26.5% or 203,400 families, while the total number of families is 767,500. However, the number of families receiving benefits is in the range of 130,000 – 135,000. The system of reimbursement for electricity consumption to the low income families is based on the three summer month average consumption and does not address the heating needs of the low income families. The average monthly electricity bill is assessed at the level of 2,835AMD, which is equivalent to 113 KWh of monthly electricity consumption.

The current electricity tariff for population is 25AMD/kWh (for those who don't enjoy time-of-use rate), which is equal to 8.3 cents/kWh. Assuming that the power reduction strategy of the Government of Armenia will be realized and the average consumption would remain unchanged, the appropriations in support of vulnerable customers must be reconsidered in order to account for the significantly increased end-use tariffs. In order to accommodate the increased electricity rates and at the same time assure the benefits to recipient families, the amount of $37 million should be budgeted for the period from 2017 to 2021.

In the case of the no-nuclear scenario, the impact on the vulnerable customers would be much higher and would amount to roughly $48 million for the period from 2017 to 2021.

12. ESTABLISH A MILESTONE SCHEDULE OF ACTIVITIES FOR THE NUCLEAR POWER PLANT PROJECT

This section provides a level one milestone schedule for the major activities of the new NPP project.

12.1 MILESTONE DESCRIPTIONS

The development of a NPP requires a great deal of planning and coordination to manage in a way that is cost effective and schedule driven. The most important phase of the project is the initial planning. This planning effort involves all aspects of the contracting philosophy, organizational development, licensing, construction and operational startup of the facility. The high level activities are further discussed below:

Developing the regulatory framework

Critical to the success of the Armenian project is to determine the requirements and criteria for design, construction and operation of a new nuclear power facility in Armenia that is consistent with generally accepted IAEA and international requirements. In this regard, it is assumed that the Armenian government will be responsible to establish an independent regulatory body to provide design requirements and inspection criteria for the new project. The schedule durations for the regulatory activities are based upon estimates for similar on-going new plant licensing efforts. The regulatory organization will require time to develop the staff and will be supplemented by international support in order to meet the schedule for a new nuclear plant in Armenia.

Establishing project management

The GoA Managing Organization will need to be developed into a fully functioning nuclear organization. There are several models for this development. The one selected will require that the team initially be developed to a level of about 50 individuals with significant support from international Architect Engineers (AEs) and outside consultants. This core team will initiate the early tasks and set up a management and human resource plan for the later phases of the project.

Endorsement of the EBID by the GoA,and obtaining of permits

This is a significant early engineering and regulatory task. It will require the use of a specialized team to finalize the Environmental Background Information Document (EBID) and support the EIA process. In particular, long-term activities in the areas of meteorology monitoring and seismic assessments will need to be started very early in the schedule. Another immediate activity is the application for permits for the additional cooling water needed for the new nuclear unit.

Establishing financing commitments

There are three phases of obtaining and establishing financial commitments. For the early phase of development, a credit line will be needed to provide for the controlled flow of cash to support the detailed design, the ordering of long lead time equipment, development of site support facilities and the funding of the management team and regulatory organization. It is anticipated that these funds will be derived from international sources.

The second phase will begin upon approval of the project to proceed with construction. The majority of these funds will be tied to clear construction contracts and milestones. Additionally, funds will be needed for the growing operational organization, as staffing and training commence. Oversight and regulatory costs will remain high during this phase. It is anticipated that these funds will be derived from international loans secured with help from the major vendor consortium and export credit agency sources.

Finally, preoperational funding will be established to support routine operations activities, working capital and to provide the necessary cash flow required to support the plant should a extended out occurred. Once the plant is fully operational and has produced electricity for sale for an extended period, other funding means such as lines of credit might be feasible.

Preparing project specifications

A critical early task is the development of the project specifications required to conduct successful bidding of the project and the subsequent management of the vendors. This task will produce very detailed technical, legal and commercial requirements and will require an experienced team of international consultants working closely with the existing GoA Managing Organization. The result will establish a working team of international vendors, AEs and local suppliers. Project specifications are anticipated for the reactor and turbine block (NSSS), the Balance of Plant (BOP), the site support facilities, the plant cooling systems, the electrical transmission facilities, the simulator, and fuel supply.

Conducting a tender through contract award

As further describe in IPS section 15, the tender process is crucial to the success of the project. A complete technical, commercial and legal agreement needs to flow from this process. The process must be fair and transparent, in order to receive international monetary support. The adequate planning and reasonable development of the products will lead to a better comparison of the lead vendors. Clear specifications and strong tender control processes will allow for the bidders to provide high quality at the lowest cost to the project. A critical aspect of the process is to assure that the contracts and scopes all fit together in a cohesive project team where a clear understanding of the division of responsibilities and schedule commitments can be achieved.

Infrastructure projects (e.g., roads, transmission lines, industrial capacity)

The development of these projects early in the process will be necessary to allow the schedule to be maintained throughout. Road and port surveys and improvements are critical for moving equipment to the site locations. Upgrades to the roads will be required for heavy loads associated with the reactor vessel, turbine and other large components. The new 400 KV transmission lines will need to be constructed allow delivery of the new reactor output. Cooling water system upgrades at the pumping station and piping will be needed. The local industrial capacity will need to be evaluated and agreements reached on improving fabrication facilities to support module construction at the site.

Manpower development projects

Manpower development projects are needed early in the schedule. Craft development and training activities will need to begin at least a year prior to construction beginning. Operator and maintenance training will require facilities to be built in an early phase of the project to support later station staffing.

Ordering long lead time items

Several long lead items will need to be ordered during the planning and development phases. As the nuclear industry expands, more types of equipment will become in tight supply. In particular, large forging such as for the reactor vessels for many vendors are in limited supply. Supplier facilities for reactor coolant pumps, steam generators, pressurizers, turbines and generators are all limited. Therefore, it is imperative that the project order these early in the project development.

Detailed design

Detailed design activities will be required to allow for equipment specification and to meet site specific requirements. These will develop the engineering to a point where materials can be ordered for the product and will bring the engineering to a level of detail to allow for adequate review, detailed construction planning to be completed and individual work packages to be generated. It will also establish the records needed to successfully manage the construction activities and to support quality and regulatory review of the effort.

Nuclear plant licensing

Nuclear plant licensing entails development and submittal of necessary design studies and documents to allow initial construction and encompasses all information needed to allow for initial operations including the development of training, procedures and all other organizational activities required for safe operations.

Site preparation

In the initial phase of the project, the site will need to be prepared. Based upon the geotechnical analyses, some areas especially beneath the reactor and turbine buildings will require engineered foundations to be developed. Underground piping and ducts will be installed. Drainage, sanitation and erosion control facilities will be provided. Site support facilities will be constructed to allow for construction and engineering teams to develop working relationships. Abandoned buildings in the vicinity of the site will be demolished or converted to workshops and storage buildings. Telephone and computer facilities will need to be installed.

Procurement

Procurement activities will largely fall to the NSSS vendor and other support contractors. However, these procurements need to be closely scheduled and monitored to assure no delays to the schedule or conflicts in delivery occur. The process will begin with the order of long lead items.

Civil construction

Civil construction will begin with the foundation of the reactor building and continue throughout the project. It will encompass all power building and permanent plant facilities. Included will be concrete, architectural steel and other civil construction activities.

Equipment Installation

Following the start of civil construction, it is anticipated that modules will be delivered and installed based bottom up construction. This will involved the use of large cranes lowering equipment in place after the walls and are poured in. The ceilings of the various rooms are then poured and the next vertical layer started. This same pattern will continue for all major building. It will be important to coordinate the design and fabrication of modules in off-site facilities. Once an area is prepared, the miscellaneous equipment and electrical equipment will be installed.

Simulator construction

The simulator design and construction will need to proceed in a timely manner to allow for operator training to begin at approximately the same time as first concrete. Reactor operator training will need to be substantially complete prior to fuel arriving on-site

Operator training

Two forms of operating training will be required. The formal reactor operating training will begin early in the project schedule. These operators will form the management team for the facility. The secondary operator staffing and training will commence later once more of the facility is in place. This will allow walk downs and use of the operators in testing programs.

Commissioning and Testing

Commissioning and testing will commence once individual systems are sufficiently constructed to allow powering and process testing to begin. The program will need to begin shortly after construction begins with test plan and procedure preparations. This will also offer an excellent opportunity to provide training to the Armenian engineering staff.

ANRA inspection

It is anticipated that ANRA inspections will begin at the time of first concrete pours and continue until the successful startup occurs. The levels of inspections will vary but the close integration of inspection teams into the construction activities is highly desired. Final inspections will correspond with fuel load, low power physics and final startup testing.

Fuel Load

Fuel load will commence upon completion of construction and during the equipment testing of the facility. Critical to fuel load will be the completion of all major equipment system especially the control room. Fuel will need to be on-site approximately 1 year prior to fuel load to accommodate the overall project schedule.

Commercial Operation

Commercial operations will begin once all testing has completed. By this time, the entire Armenian operational organization will be in place to safely and successfully operate the new facility with limited international support.

12.2 LEVEL 1 SCHEDULE

A Level 1 schedule has been developed in MS Project that includes all listed activities (Figure 12.1). It has been prepared with activities schedule in sequences that have been benchmarked with similar efforts in the United States and with durations based upon best estimates of international practices and experience. Highlights and descriptions of these schedule logic and durations are provided below.

Developing the regulatory framework

Development of the regulatory framework needs to begin immediately to allow correct planning and execution of the licensing portion of the project. The development of the rules has been scheduled to begin January 2009 and require about 6 months. This would be followed by the staffing and development of the regulatory organization which has to be in place to allow review and approval of the license application and inspections for the project.

Establishing project management

GoA Managing Organization must begin to form immediately in January of 2009. Full initial staffing of approximately 50 individuals is expected to take a full year. Priority activities that are dependent on the organization development will be the establishment of contracting approach, all contract activities, detailed planning and scheduling and overall project management.

Approval of EIA and permits

The completion of the EBID to initiate the EIA process will commence upon establishment of the Managing Organization. It is important to complete the seismic evaluation and other studies required completion of the EBID as the duration for this task is approximately 18 months for review and approval. During this period, water use permits and other required permits will also be obtained.

Establishing financing commitments

An initial financing is expected to be available in January 2009. This should be shortly followed by funding commitments in the range of $500M that will support project development and the ordering of long lead equipment. If this is not realized very early in the project then the schedule will be delayed. The second major financing is expected to begin shortly after project start (2 months) and require approximately 18 months duration. It will be closely tied to the tender process and must be complete prior to the award of the NSSS contract.

Preparing project specifications

Preparation of project specifications will short begin after the project organization is initially formed and the contracting approach has been selected. The initial specifications are anticipated to require approximately 5 months to prepare.

Conducting a tender through contract award

Once the project specifications are prepared, the tender will begin with the Expression of interest and prequalification of vendors. It has been assumed that much of this can move in parallel. Once bidders have been selected the effort will move to bid preparation and review to be followed by contract negotiations. The full duration for these activities is 15 months.

Infrastructure projects (e.g., roads, water, transmission lines, industrial capacity)

Infrastructure design and construction will initiate approximately 5 months following project initiation. The design phase will require approximately 1 year with construction commencing approximately 4 months after design initiation. The duration of the facility construction has been estimated at 15 months while the infrastructure construction has been estimated at 2 years.

Manpower development projects

This includes Human Resources planning and the development of skilled labor and supplier support internal to Armenia. This will begin approximately 6 months after project initiation and will extend for a period of approximately 4 years.

Ordering long lead time items

The long lead items will be ordered approximately 3 months following award of the NSSS contract. The expected duration for delivery of these items is 30 months.

Detailed design

Detailed design will begin 2 months after NSSS contract award and will require approximately 2 years to complete. Significant activities related to design are module fabrication, equipment procurement and the completion of regulatory review.

Nuclear plant licensing

Plant licensing will formally begin with the submission of the EIA. It is dependent upon the formation of the regulatory framework and the development of the regulatory organization. The duration of review and response to questions is 28 months.

Site preparation

Site preparation will begin following the initial regulatory reviews have been completed and assurances are known on remaining design issued. The initial site preparation is expected to require 10 months and is required prior to first concrete.

Procurement

Procurement of the majority of equipment will begin approximately 5 months after the beginning of detailed design and will last 22 months. Procurement will continue for minor items throughout the construction process.

Civil construction

Civil construction will begin following completion of design and regulatory approvals. It is anticipated to require 2 years to complete.

Equipment Installation

Equipment installation will commence approximately 6 months after first concrete and will continue for 33 months.

Simulator construction

Simulator design will begin 3 months after NSSS contract award and be complete in 1 year. The simulator construction will occur in a building provided as part of facility construction and will be completed within 18 months following design.

Operator training

Operator training will begin approximately 5 months after the start of simulator construction. There will need to be at least five license classes with durations of 15 month each prior to final testing and fuel load. However, these classes can overlap, using the simulator during different periods of the day and week. The total operator training period will be 30 months.

Commissioning and Testing

Commissioning and testing will begin at the completion of equipment installation with final startup testing upon fuel load. The full test program has a duration of 15 months.

ANRA inspection

It is anticipated that ANRA inspections will be conducted throughout the project, from first concrete until the end of commissioning for a duration of 72 months.

Fuel Load

Fuel fabrication for the new unit will begin approximately 6 months following award of the NSS contract. With a duration of 2 years, it is anticipated that the roads and facilities needed for delivery would be complete to support the 12 month delivery. It is anticipated that fuel inspection and loading would require approximately 10 months to complete.

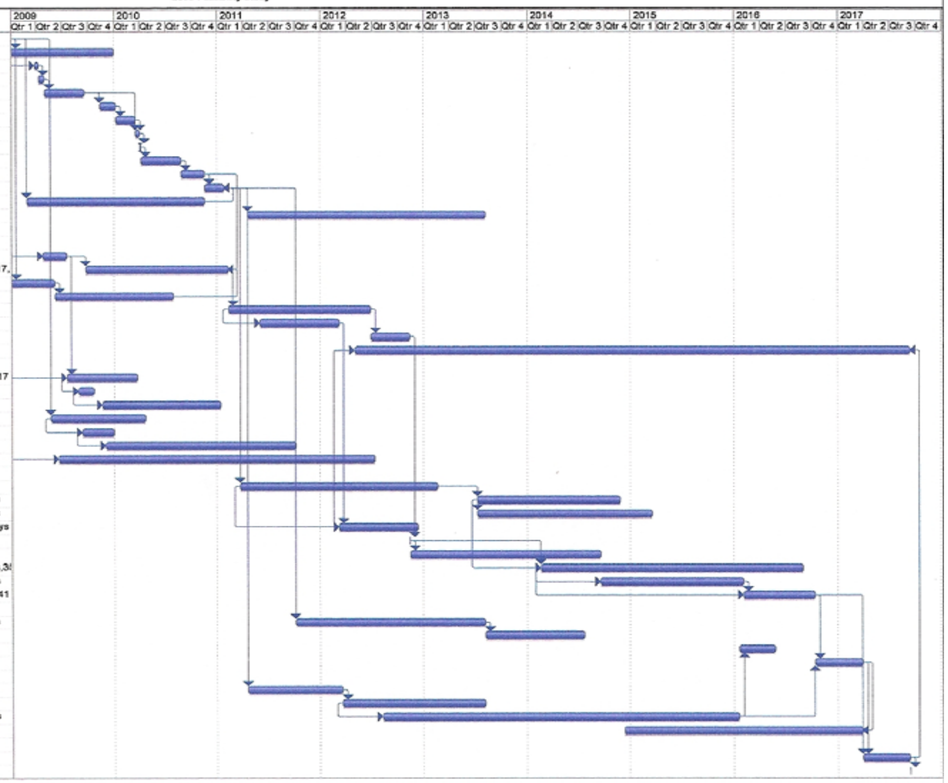
Commercial Operation

Commercial operation would commence upon complete of commissioning and testing and upon regulatory approval approximately 80 months after contract award.

Figure 12-1, Level 1 Project Schedule

ANNP Schedule
2008 Feasibility Study

ID	Task Name	Duration	Start	Finish	Predecessors
1	Obtain Development Financing	1 day	Thu 1/1/09	Thu 1/1/09	
2	Establish Project Organization	260 days	Fri 1/2/09	Thu 12/31/09	1
3	Establish Tender Committee	10 days	Fri 3/27/09	Thu 4/9/09	2SS+60 days
4	Selection of Contract Approach	15 days	Fri 4/10/09	Thu 4/30/09	3
5	Prepare Bid Specifications	100 days	Fri 5/1/09	Thu 9/17/09	4
6	Expression of Interest	40 days	Fri 11/13/09	Thu 1/7/10	5FS+40 days
7	Prequalification of Bidders	50 days	Fri 1/8/10	Thu 3/18/10	6
8	Distribution of Draft Specificatio	10 days	Fri 3/19/10	Thu 4/1/10	5,7
9	Bidder's Conference	3 days	Fri 4/2/10	Tue 4/6/10	8
10	Submission of Bids	100 days	Wed 4/7/10	Tue 8/24/10	9
11	Evaluation of Bids	60 days	Wed 8/25/10	Tue 11/16/10	10
12	Award of Contracts	50 days	Wed 11/17/10	Tue 1/25/11	11,13FF
13	Establish Financing Commitmen	450 days	Fri 2/27/09	Thu 11/18/10	1FS+40 days
14	Order Long Lead Items	600 days	Wed 4/20/11	Tue 8/6/13	12FS+60 days
15					
16					
17	Award Owner's A/E Contract	60 days	Fri 4/24/09	Thu 7/16/09	2SS+80 days
18	Develop EIA Submittal	360 days	Wed 9/23/09	Tue 2/8/11	11FF+60 days,17,
19	Develop Regulatory Structure	110 days	Fri 1/2/09	Thu 6/4/09	1
20	Establish Regulatory Organizati	300 days	Fri 6/5/09	Thu 7/29/10	19
21	Regulatory Review of EIA	360 days	Wed 2/9/11	Tue 6/26/12	18
22	Request for Information	200 days	Wed 6/1/11	Tue 3/6/12	21SS+80 days
23	Regulatory Approval	100 days	Wed 6/27/12	Tue 11/13/12	21
24	ANRA Regulatory Inspections	1400 days?	Wed 5/2/12	Tue 9/12/17	37SS,54FF
25					
26	Facility Design	180 days	Fri 7/17/09	Thu 3/25/10	2SS+100 days,17
27	Facility Contracting	40 days	Fri 8/28/09	Thu 10/22/09	26SS+30 days
28	Facility Construction	300 days	Fri 11/20/09	Thu 1/13/11	27SS+60 days
29	Infrastructure Design	240 days	Fri 5/22/09	Thu 4/22/10	1FS+100 days
30	Infrastructure Contracting	80 days	Fri 9/11/09	Thu 12/31/09	29SS+80 days
31	Infrastructure Construction	480 days	Fri 12/4/09	Thu 10/6/11	30SS+60 days
32	Manpower Development	800 days	Fri 6/19/09	Thu 7/12/12	2SS+120 days
33					
34	Develop Detailed Design	500 days	Wed 3/23/11	Tue 2/19/13	12FS+40 days
35	Modular Fabriciation	360 days	Wed 7/10/13	Tue 11/25/14	34FS+100 days
36	Equipment Procurement	440 days	Wed 7/10/13	Tue 3/17/15	34FS+100 days
37	Site Preparation	200 days	Wed 3/7/12	Tue 12/11/12	22,34SS+80 days
38	First Concrete	1 day	Wed 11/14/12	Wed 11/14/12	23
39	Civil Contruction	480 days	Thu 11/15/12	Wed 9/17/14	38
40	Equipment Installation	660 days	Wed 2/19/14	Tue 8/30/16	38FS+120 days,3
41	Control Room Installation	360 days	Wed 9/17/14	Tue 2/2/16	40SS+150 days
42	Equipment Testing	180 days	Wed 2/3/16	Tue 10/11/16	40SS+90 days,41
43					
44	Fuel Fabrication	480 days	Wed 10/5/11	Tue 8/6/13	12FS+180 days
45	Fuel Delivery	250 days	Wed 8/7/13	Tue 7/22/14	44
46	Fuel Inspection	90 days	Wed 1/20/16	Tue 5/24/16	51
47	Fuel Load	120 days	Wed 10/12/16	Tue 3/28/17	51,42
48					
49	Simulator Design	240 days	Wed 4/20/11	Tue 3/20/12	12FS+60 days
50	Simulator Construction	360 days	Wed 3/21/12	Tue 8/6/13	49
51	Operator Training	900 days	Wed 8/8/12	Tue 1/19/16	50SS+100 days
52	Maintenance Training	600 days	Wed 12/10/14	Tue 3/28/17	47FF
53					
54	Commissioning and Testing	120 days	Wed 3/29/17	Tue 9/12/17	42,47
55	Comercial Operations	1 day	Wed 9/13/17	Wed 9/13/17	54



Project: Armenia_Level_1_Schedule_08
Date: Fri 8/22/08

Task | Split | Progress | Milestone | Summary | Project Summary | External Tasks | External Milestone | Deadline

Page 1

13. PUBLIC CONSULTATION AND DISCLOSURE PLAN (PCDP) FOR THE NEW NUCLEAR POWER UNIT PROJECT IN ARMENIA

13.1 INTRODUCTION

13.1.1 Policy Statement

By Decision No. 48, adopted on November 29, 2007 the Government of Armenia announced its intent to explore a possibility of building a new nuclear power unit in the country. This decision is in line with the provisions of the National Energy Strategy and the Action Plan of the Ministry of Energy and Natural Resources (MoENR)[65], pursuing the overall goal of creating conditions for sustainable development of the Armenian economy, financial stability and economic efficiency, and successful implementation of social policies, while stressing the paramount importance of ensuring national energy security and independence for Armenia.

This is an informed decision based on the results of specific studies carried out by the GoA in previous years, indicating that new nuclear generation is the best option that will permit the country to diversify the fuel mix for power generation and ensure power supply at least cost to the society. The decision is in compliance with the provisions of the national security strategies of the Republic of Armenia and the principles and guidelines of the international community.

This is a conditional decision subject to:

(i) Proving the economic and technical feasibility of the project;

(ii) Positive outcome of the environmental impact assessment of the project;

(iii) Public acceptance of the project.

To implement the project, Armenia will have to make important decisions and execute an action plan in a timely manner, including implementation of a public consultation and disclosure process to assess acceptance of interested and affected parties in the country as well as abroad. The project implementation will require close cooperation between Armenia and the international donor community and neighboring countries through IAEA.

13.1.2 Objectives of the PCDP

The overall objective of this part of the Initial Planning Study is to suggest a well-defined technically and culturally appropriate public consultation and disclosure plan for the new nuclear power unit project in Armenia. This section defines the policies and procedures that will be used for information disclosure and the organization of the public consultation to ensure that adequate and timely information is provided to all stakeholders and that they are given sufficient opportunity to express their opinions and concerns, and, that such concerns are taken into account in the decision-making process.

The implementation of the public consultation and disclosure plan will serve the purposes detailed below.

1. Raise public awareness of the benefits of nuclear power for Armenia.

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[65] Adopted by the GoA on November 29, 2007.

Educational activities should be part of the public consultation and disclosure plan to ensure favorable view of the project in support of objective 1 above. Such activities are necessary because of the weak knowledge base of the general public in the field of energy in general and nuclear energy in particular.

2. *Gain public support for the project.*

   Public acceptance of the project is a very important issue for nuclear power worldwide, and especially so in Armenia, where fossil fuel resources that can be used for energy generation are scarce and where nuclear energy has been identified as the most economically feasible option for the country. However, the general public is largely unaware of the benefits of nuclear energy, and the misperception of its dangers is often overstated in public opinion forums.

3. *Make sure that neighboring countries are fully informed about the project in an appropriate and timely manner.*

   As the proposed project is within proximity of some neighboring countries, it is important that Armenia take all appropriate measures to prevent, reduce and control any potential trans-boundary impacts. Armenia, as a signatory to Espoo 1991 Convention, will need to notify any party located across national borders which it considers likely to be affected by the project no later than when informing its own public. Information sharing in a trans-boundary context is an evident part of the proposed communication plan.

4. *Offer the international community at large and the international donor community in particular assurances* that the decision-making process and the implementation of the project will be planned and carried out in recognition of international norms and in compliance with the requirements of the international financing institutions and international regulatory agencies in the nuclear field.

13.1.3 Principles of the PCDP

The GoA fully adheres to the IAEA's principle of transparency requiring that "bodies involved in the development, use and regulation of nuclear energy make available all relevant information concerning how nuclear energy is being used, particularly concerning incidents and abnormal occurrences that could have an impact on public health, safety and the environment"[66].

Public consultation involves exchange of information with the interested and affected parties to facilitate a shared understanding of issues under consideration. It is a process whereby individuals and groups can appropriately contribute to decision-making and influence the outcome. In order to achieve this, the proposed process for public consultation and disclosure should be:

- Planned, open and accountable;
- Structured to consider the information needs and the background knowledge of interest groups and designed reach out to all interested and affected parties;
- Iterative in nature and subject to periodic updating as we learn from outside comments;

[66] Handbook on Nuclear Law. IAEA. Vienna 2003. P. 10.

- Continuous throughout the decision-making process;
- Documented and monitored to ensure its effectiveness.

A process of information sharing and public involvement defined in the PCDP is built on the above principles to help foster a positive image of the proposed project and its acceptance by the stakeholders.

13.1.4 Limitations to Information Disclosure

Through its commitment to open communication about the planned nuclear power project, the GoA demonstrates its willingness to listen to third parties with the purpose of taking into account their interests and concerns and benefiting from their contributions. However, successful implementation of the project requires establishing partnership with project sponsors and any private parties who may have concerns about client confidentiality. Such concerns could affect their willingness to participate in the project and it is for this reason that information concerning the project will be made available to the public in the absence of compelling reasons for confidentiality.

Decisions about exceptions from the project information available to the public will be made at the GoA’s discretion. However, at this stage, it is possible to state that the information about the project available to the public will include:

- General technical description of the project and the project’s site;
- Nuclear safety-related issues;
- Emergency planning measures;
- Project’s potential impacts on environment and the public;
- Project’s impact mitigation measures;
- Information about interested and affected parties.

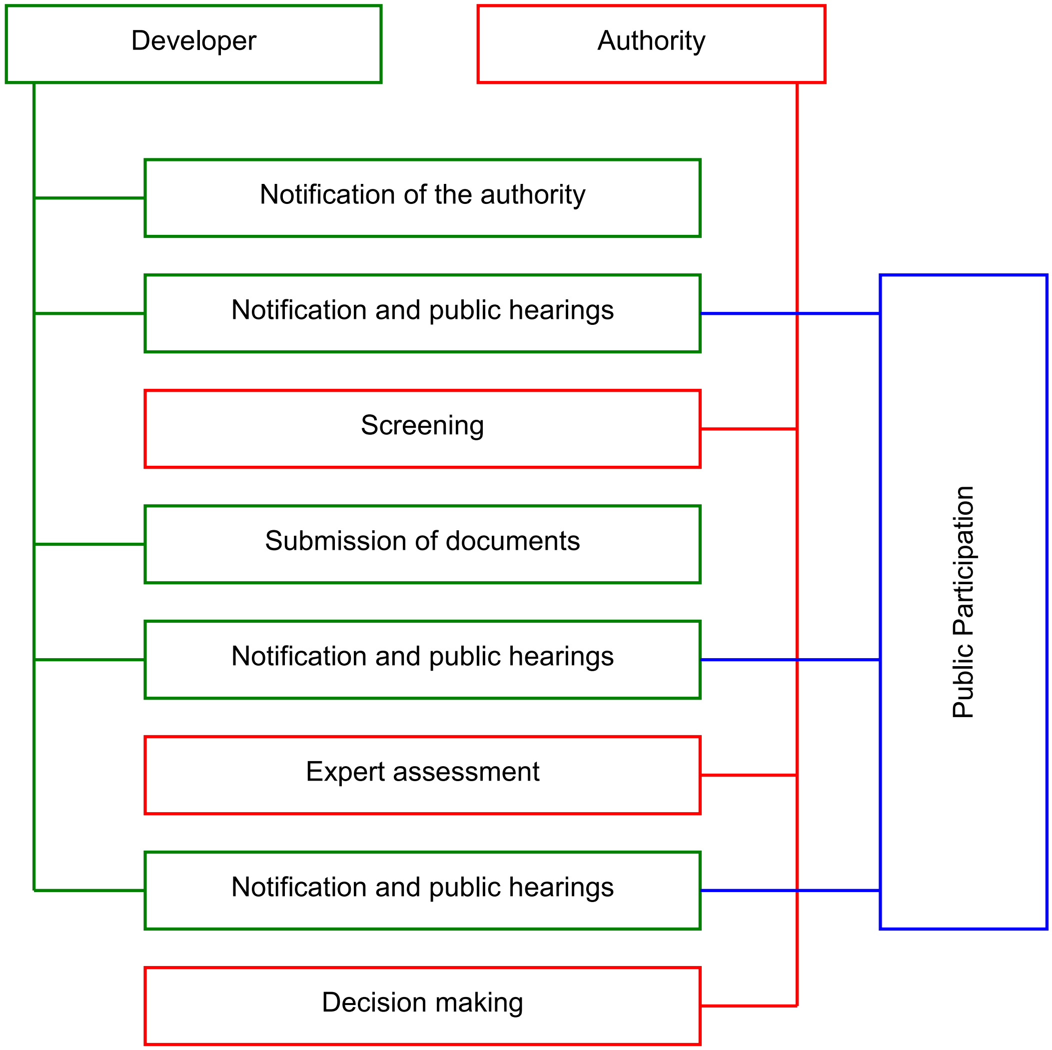
Information that the project implementers might decide to withhold from public domain may include:

- Information that could pose a threat to the national security of Armenia;
- Information related to procurement processes and details of contractual arrangements;
- Financial, technical or other business proprietary or commercially sensitive information communicated by private entities, unless permission is given to release such information;
- Working documents intended for internal use only.

13.2 LEGAL FRAMEWORK AND JURISDICTION

13.2.1 National Legal Framework

In Armenia, provisions on public consultation at the national level are described in the RoA Law on Environmental Impact Assessment promulgated on 20 November 1995. This law establishes the process for assessment of projects likely to have an adverse environmental impact including public notification and participation as shown in the following diagram.



The Law on EIA does not categorize development projects according to the gravity of their potential impact on the environment and society. All projects regardless of their impact are subject to the same EIA procedure. The process of EIA can take between 150 and 190 days for a given project.

In order to improve the legislative framework established by the Law of 1995, there was initiated development of a new law on EIA. The draft text of the new law would establish timeframes for environmental reviews, obligations and rights of the developer including transfer of some of the responsibilities for organization of the public consultation process from the project developer to government authorities and local self-government bodies. The draft law would also establish a process for public involvement while requiring that the procedures for public notification and information be developed in a separate document to be adopted by the GoA.

13.2.2 International Regulation and Guidelines

International conventions establish a consistent and comprehensive basis for proper protection of people and environment against the radiation risks. Both regionally and globally, bilateral and multilateral instruments are building an international law of nuclear energy. Legally binding agreements between States are increasingly recognized as an important element of the global safety culture for improving nuclear safety worldwide. To the extent that Armenia has adhered to any international legal regimes, their provisions and requirements must be respected throughout the lifetime of the project.

The public information and disclosure plan described in this chapter takes into account provisions of the following international agreements:

- The Protocol on Strategic Environmental Assessment to the Convention on Environmental Impact Assessment in a Trans-boundary Context, ratified by Armenia in 2003.
- The Aarhus (Denmark) Convention on Access to Information, Public Participation in Decision-making and Access to Justice in Environmental Matters, ratified by Armenia in 2001.
- The Convention on Nuclear Safety, ratified by Armenia in 1998.
- The Espoo (Finland) Convention on Environmental Impact Assessment in a Trans-boundary Context, ratified by Armenia in 1997.
- The Convention on Assistance in the Case of Nuclear Accident or Radiological Emergency, ratified by Armenia in 1993.
- The Convention on Early Notification of a Nuclear Accident, ratified by Armenia in 1993.

In addition, the following guidelines of the international financing institutions and regulatory agencies in the nuclear energy field have been duly considered to incorporate their requirements in the proposed PCDP:

- EBRD Public Information Policy 2006.
- EBRD Environmental Procedures 2003.
- EBRD Environmental Policy 2003.
- EU Guidance on EIA 2001.
- The World Bank Policy on Disclosure of Information 2002.
- World Bank Operational Manual, OP 4.01, Environmental Assessment. 1999 (revised in 2004 and 2007).
- Handbook on Nuclear Law. IAEA, Vienna, 2003.
- EU Directive on Environmental Assessment (85/337/EEC), amended by EC Directive 97/11/EEC.

13.3 PROJECT SETTING AND STAKEHOLDERS

13.3.1 Project Setting

The Government of Armenia is considering the possibility of constructing a new nuclear power unit at the site of the existing Armenian Nuclear Power Plant (ANPP) to replace the capacity of the existing ANPP Unit 2 when it is shut down for decommissioning. It is currently planned that a pressurized water reactor (PWR) of approximately 1,000 MW capacity or a CANDU plant of approximately 740 MW will be built at the existing ANPP site.

The ANPP site, with a nominal elevation of approximately 930 meters above sea level, is located near the town of Metsamor in Armavir region. ANPP is approximately 9.2 km east-northeast of the town of Armavir, and approximately 32 km west of Yerevan, the capital city of Armenia. The site lies in the western part of the Ararat Valley on the southern flanks of Mount Aragats. An aerial view of the ANPP site is shown below.

The existing ANPP site was designed to house 4 units, of which 2 were built in the late 1970's. The site currently has two power-generating units with Soviet-designed VVER-440 (V-270) reactors. The first power unit at the ANPP was placed in the first grid connection on December 22, 1976, and the second on January 5, 1980. The installed power capacity of the units is 407.5 MW each. Both units were shutdown in early 1989 as a safety measure following the 1988 Spitak earthquake. Unit 1 remains in a shutdown condition while Unit 2 was restarted in 1995 following extensive inspections, safety upgrades, and refurbishment of equipment.

Engineering studies and preliminary work for units 3 and 4 (employing VVER-440 reactors) were performed in the mid-1980s, but the units were not constructed. The proposed new unit would be of current generation design with enhanced safety features as compared to the existing ANPP units. It is proposed that the new unit would occupy the area previously planned for Units 3 and 4.

ANPP Unit 3 will consist of one reactor plant and auxiliaries. A specific plant design has not been chosen for ANPP Unit 3, but candidate reactors all use pressurized water as the primary coolant. Water under high pressure is pumped through the reactor core where it is heated by contact with fuel rods containing uranium. The heated water passes through the steam generators where the heat is transferred to the secondary loop, and then returns to the core. In the steam generators, water in the secondary loop is heated to boiling. This steam drives a turbine-generator system, is cooled and condensed back to a liquid in the condenser, and returns to the steam generators. The condenser is cooled by a circulating water system employing one or more cooling towers.

13.3.2 Project Impacts

The new nuclear power unit will have various impacts on the Armenia environment, society and economy during both the construction and operation periods.

13.3.2.1 IMPACTS DURING CONSTRUCTION

It is anticipated that the project will be the largest construction project in the country. Such a large project will cause a strain on resources in two ways:

- Local resources at the site will be strained to accommodate such a large group of workers; and,
- Other projects in the country will be strained because resources that they normally rely on could be diverted to the nuclear site.

Construction of Unit 3 will involve a construction workforce estimated to be 2,500 to 3,000.The work force will include as many as 2,000 skilled construction crafts, such as welders, electricians, instrument technicians, iron workers, etc. To the extent that these skilled workers come from Armenia or nearby countries, this may impact other projects requiring such personnel. Preliminary assessments indicate that Armenia may not have sufficient skilled workers for such a project and must embark immediately on a program to train and qualify such personnel.

In the area near the site, the large size of the work force will require housing, schools, medical facilities, food supply and other basic services. This may be complicated by the fact that the work force could include a large contingent of foreign workers. Some of the skills needed at the construction site could be unique and require that special schools be set up to train adequate numbers of construction workers in the needed skill.

Assuming that 80% of the construction workforce will be housed in Armavir region, this would represent a two to three percent population increase, primarily in the urban centers of Armavir and Metsamor towns. If these personnel were to bring along their families, it will place stress on housing and community services in the area. It is highly likely that some of the skilled personnel will come from outside Armenia and they may present additional stresses on the communities of the region.

Away from the site, other projects could find that they are unable to attract necessary workers for their projects. This could lead to these projects falling behind schedule or not being completed. It is possible that competition for labor could lead to a general increase in the salary structure as companies raise wages in order to hire people away from the nuclear project.

13.3.2.2 IMPACTS DURING OPERATION

Operation of the new nuclear power unit imposes a need for emergency planning in case of accidents. Resolution No. 194, "On the Approval of the National Plan for the Protection of the Population in the Event of a Nuclear and (or) Radiation Accident at the Armenian Nuclear Power Plant," adopted by the GoA on January 17, 2008, sets out responsibilities for response to an emergency at ANPP. It is expected that the plan in force will serve as the model for planning of emergency response for the new unit.

The Emergency Plan involves many governmental organizations, and involves Administrations of Aragatsotn, Armavir, Kotayk and Shirak regions, local self-government administrations of Armavir, Metsamor, Vagharshapat (Echmiadzin) towns of Armavir region, Ashtarak and Talin towns of Aragatsotn region, Gyumri city of Shirak region, Hrazdan and Yeghvard towns of Kotayk region, 36 villages located in Armavir region, and eight villages in Aragatsotn region, as well as local hospitals, polyclinics, rescue service offices, police stations, railway stations, and telephone company Armentel.

13.3.2.3 TRANS-BOUNDARY CONTEXT OF THE PROJECT

The Republic of Armenia is situated in the Trans-Caucasus, having borders with Georgia Republic to the north, Azerbaijan to the east and south, Iran to the south, and Turkey to the west.

The closest border with Turkey, demarcated by the river Araks, is approximately 16 km to the south of the project site. The Turkish city of Igdir, population 60 thousand, is approximately 30 km to the south of the site.

Out of all the neighboring countries Turkey is most likely to be affected by the nuclear power project development in Armenia as a result of public exposure. However, Armenia and Turkey have no diplomatic or other official relations. Moreover, the Armenian Law on EIA (1995) makes no legal provisions requiring notification of affected neighboring countries. Nevertheless, taking into consideration the potential trans-boundary effects of the proposed project and willing to act in good faith with the obligations codified in the international legal instruments to which Armenia is a signatory, the GoA will make an effort to inform Turkey of the proposed activity and be willing to offer this country a chance to express its opinions and concerns.

To this end, the GoA is mindful that:

- One of the principles of customary international law is that the territory of a State must not be used in such a way as to cause damage in another State and that, consequently, control measures are necessary. Due to the nature of nuclear power projects, proximity of the proposed project site to neighboring countries opens up a possibility of trans-boundary impact in the event of an accident. According to the IAEA, "although many human activities taking place within the territory of a State can result in damage beyond its borders, nuclear energy has been deemed to involve particular risks of radiological contamination transcending national boundaries."[67]

- The Espoo Convention sets out the obligations of Parties to notify and consult each other on all major projects under consideration that are likely to have a significant environmental impact across borders. In particular, it specifies in its Article 3 that "the Party of origin shall, for the purposes of ensuring adequate and effective consultations notify any Party which it considers may be an affected Party as early as possible and no later than when informing its own public about the proposed activity."

- The international co-operation principle formulated by the IAEA requires that the users of nuclear technologies and the regulators of nuclear activities maintain close relationships with counterparts in other States and in relevant international organizations[68]. Article 16 of the IAEA Convention on Nuclear Safety states that "Each Contracting Party shall take the appropriate steps to ensure that, insofar as they are likely to be affected by a radiological emergency, its own population and the competent authorities of the States in the vicinity of the nuclear installation are provided with appropriate information for emergency planning and response."

- The Convention on Early Notification of a Nuclear Accident establishes a notification system for nuclear accidents that have the potential for international trans-boundary release that could be of radiological safety significance for another States. It requires States to report the accident's time, location, radiation releases, and other data essential for assessing the situation.

In its Article 7, the Convention on Early Notification of a Nuclear Accident requires that notification is to be made to the affected States directly or through the IAEA, and the IAEA itself. To this effect, the Agency maintains an up-to-date list of national authorities and points of contact of relevant international organizations. In the light of this requirement, the GoA will send a request to the IAEA to transfer the project documentation normally available to the international community to relevant Turkish authorities. Such a request to the IAEA is to be sent out when the GoA starts the national process of public information and disclosure.

13.3.3 Interested and Affected Parties in Armenia

There are three main groups of organisations and individuals who it may be appropriate to consult during planning for construction of a new nuclear unit in Armenia. These are:

A. Environmental authorities;

B. Other interested organisations; and,

C. The general public in the affected area.

Types of organisations to be included in these three groups are listed below.

A. Environmental Authorities

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[67] Handbook on Nuclear Law. IAEA. Vienna 2003. P.9.

[68] Idem. P. 10 - 11.

- Regional and local authorities;
- Authorities responsible for pollution control including water, waste, soil, noise and air pollution;
- Authorities responsible for protection of nature, cultural heritage and the landscape;
- Health and safety authorities;
- Land use control, spatial planning and zoning authorities; and,
- Authorities in neighbouring countries where trans-boundary impacts may be an issue.

This group is represented by the GoA Ministries and agencies, governors of Armavir, Aragatsotn, Kotayk and Shirak regions, mayors of Armavir, Metsamor and Vagharshapat (Echmiadzin) towns, heads of the villages in Armavir and Aragatsotn regions.

B. Other Interested Parties

- Local, national and international environmental and social interest groups;
- Sectoral government departments responsible for agriculture, energy, forestry, fisheries, etc. whose interests may be affected;
- International and trans-boundary agencies whose interests may be affected, for example, cross-border river basin commissions;
- Businesses that will affected by the construction or operation of the plant;
- Employees' organisations such as trades unions;
- Hotels or other lodging establishments;
- Groups representing users of the environment, for example, farmers, fishermen, hunters, anglers, tourists;
- Local wildlife groups;
- Research institutes, universities and other centres of expertise;
- The general public in the affected region.

C. The General Public

- Land owners and residents;
- General members of the local and wider public;
- Elected representatives and community figures such as religious leaders or teachers;
- Local community groups, residents groups, NGOs.

13.3.4 Project Implementers and Parties Involved in the PCDP Implementation

The project developer is the Government of Armenia. The Ministry of Energy and Natural Resources bears the overall responsibility for the project implementation, including the implementation of this PCDP.

13.4 PUBLIC CONSULTATION AND DISCLOSURE PROCESS

13.4.1 Roles and Responsibilities

As the project moves from development to implementation, its PCDP will be formalized through the institutionalization of the PCD function. To this end, the Government of Armenia should establish a Steering Committee in charge of the PCDP planning and implementation to carry out the following functions:

1. Planning, budgeting and implementing the PCDP activities;
2. Establishing a list of organisations and individuals who are interested in the project and updating this list as the project develops;
3. Creating and training a secondary group of communicators selected from members of the public;
4. Continuously assessing stakeholders' needs and monitoring effectiveness of the PCDP activities;
5. Processing feedback received as a result of the PCDP implementation;
6. Preparing project update reports to be issued to the public upon request;
7. PCD documentation filing.

The Committee will consist of a PCDP Chairman and a number of experts. The PCDP Chairman will bear overall responsibility for the PCDP process management including development of corresponding budget. The number of the experts will be decided by the GoA, aiming to establish the necessary expertise in various complex issues of the nuclear power project. The Steering Committee will be created at an early stage in the project planning process to ensure appropriate public involvement in the decision-making.

The GoA might decide to create the Steering Committee internally and nominate experts from organisations and agencies primarily concerned by the project, i.e. the MoENR, ANRA, PSRC, specialized industry research institutes, the Ministry of Nature Protection etc. Representatives of NGOs and other public organizations might also be nominated as Committee experts. Alternatively, the PCDP implementation could be outsourced to an external organization, public or private, with evident expertise in organizing public communication activities.

.The PCDP Steering Committee will be the first implementers of the public consultation and disclosure plan. In addition to being in charge of carrying out the PCDP activities described below, they will also be responsible for development of detailed plans and production of accurate materials in the appropriate media for use by those making presentations. Since the intent of the project is to reach a broad cross section of the public, it will be necessary to develop different set of materials for different groups; material appropriate for 12 year old students is not appropriate for engineers and what is appropriate for engineers may not be appropriate for pensioners.

A secondary group of people to conduct the communication activities will be selected from certain members of the public. They will receive training so that they can present an accurate picture of the project. These persons will be teachers, engineers, business people and others who have an interest in seeing that an accurate and complete picture is available to the public.

13.4.2 PCDP Activities

The PCDP activities presented below are developed to cover all the available communication media. They can be used as separate modules to allow for flexible use of each activity throughout the PCDP implementation period and project lifetime. Below follows detailed description of the planned activities.

Project Public Data Room

Project public data room will be open to public access in a convenient and easy to access location, preferably in Yerevan city. It will have on display various information (posters, leaflets, brochures etc) about nuclear energy in general and its importance for Armenia, the technical description of the project, benefits and possible impacts on nature, society and economy, as well as, the affected communities, and proposed mitigation measures. The information for displays and hand-out materials will be taken from this PCDP, the project initial planning studies and environmental background information document.

The public data room will be opened once the full project documentation package is complete including the initial planning studies and environmental background information document remain functional through to the beginning of the construction period. It will be accessible to public on weekends and workdays, possibly with one or two days off during the working week. It will be attended by experts who will conduct guided tours and animate discussions. The public data room will give a chance to people who are nervous about standing up and speaking at a public meeting to feel more comfortable speaking to someone on a one-to-one basis. The public data room will have a visitors' log book where members of public will be able to write their comments, opinions and formulate requests that will be regularly responded to.

Project Website

The project website will be launched with the same objectives as the project public documents room described above. The website will have an electronic discussion forum facility to give all interested parties a chance for an open discussion of the project's advantages and disadvantages. It will also be used for placing advance notices of the public meetings and other PCDP-related activities to provide date, time, location names of speakers, items to be discussed, and any appropriate background documents and information.

Meeting notices, changes to meetings, and cancellations will be updated each working day, if required, on the project website.The website will also provide a telephone hotline number described below.

Telephone Hotline

A telephone hotline will be established for the project in support of the PCDP activities. The hotline will be used to record opinions, complaints and requests of members of public. The hotline operation might be assured through the customer call centre to be opened by the electricity distribution company ENA as required by the Public Services Regulatory

Commission (PSRC) of Armenia. The line will be toll free and operated for 24 hours 7 days a week.

Notices Announcing the Project in the Neighbouring Area and at the Offices of Local Authorities

The notices announcing the project will be posted prominently in the neighbouring areas and at the offices of local authorities. The notices will briefly describe the project, its impacts on the local community and give preliminary dates for the start of construction and commercial operation of the new unit. The notices will be posted in the following localities:

- Office of the Governor the Armavir region;
- Municipalities of the cities Armavir and Metsamor of the Armavir region;
- Communities in the area within 5 km radius of the ANPP, namely:
  - Villages Aknalich, Taronik, Arshaluys, Maisian, Ferik of the Armavir region, and
  - Village Nor Yedesia of the Aragatsotn region.

Publications about the project in national and local newspapers

Initial announcements about the project will be published in the following national and local papers:

- *"Hayastani Hanrapetutyun",* in the Armenian language, circulation 6,000;
- *"Aravot",* in the Armenian language, circulation 5,350;
- *"Novoye Vremia",* in the Russian language, circulation 5,000;
- *"Golos Armenii",* in the Russian language, circulation 3,500;
- *"Delavoy Express",* in the Russian language, circulation 3,000;
- *"Hayrenakanch*", in the Armenian language, Armavir region local newspaper;
- *"Metsamor",* in the Armenian language, Metsamor municipality newspaper;
- *"Vaghrashapat",* in the Armenian language, Vagharshapat city local newspaper.

The notices will have brief information about the new nuclear power unit project in Armenia, its location and forecasted timing of the start of construction activities. They will also contain information about the location and opening hours of the project data room, its website address, the hotline number and extend an invitation to all interested parties to communicate their opinion and comments to the PCDP office.

Advertisements on TV and Radio

Advertisements on TV and radio will be designed to inform the public about the project, its benefits and potential impacts and contain information about the location and opening hours of the project data room, its website address, the hotline number. Information on the benefits of the project for the Armenian economy will be a prominent part of the advertisements. The advertisements will be run on the following media channels:

- *“Public TV of Armenia”* and *“Public Radio of Armenia”*;
- *“Yerkir media”* private TV company;
- Armavir city local TV company *“ALT TV”*;
- Armavir city local TV company *“Noy Hayastan”*;
- Vagharshapat city local TV company *“Echmiadzin”*.

Roundtable Discussions on TV

Roundtable discussions on TV will be organised to highlight the benefits of the project to Armenia. The MoENR and other Government official might take part in such roundtable discussions as well as representatives of interested NGOs, associations of NGOs and members of the public.

Leaflets and Brochures

Leaflet and brochures about the project will give brief details of what is proposed with a plan or map for review and comment, describing the project, its purpose and economic benefits, and inviting comments.

The printed materials will give contact details for information and comment. The materials will be widely available in local centres such as libraries, town halls and post offices. Where possible, such documents will be delivered to households and businesses in the area.

Public Meetings with Experts

Public meetings will be held in government offices in Yerevan and in the vicinity of the new plant. A public meeting is a planned encounter open to member of the public between one or more the project experts and one or more outside persons physically present at a single meeting site, with the expressed intent of discussing substantive issues that are directly associated with the new nuclear power project in Armenia.

The public meetings will be primarily announced on the Public Meetings Schedule page of the project’s website approximately 10 days in advance. Members of the public who do not have access to the Internet will be able to contact the public data room for information on scheduled meetings. Meeting announcements will include the date, time, and location of the meeting, as well as its purpose, the project experts and other officials, as well as outside participants, who plan to attend, and the name and telephone number of PCDP Steering Committee contact for the meeting.

Such meetings will be held to explain the benefit of the project and disseminate accurate information on the risks and benefits of nuclear power in comparison to the risks and benefits of other forms of generating electricity. Because this is a public issue, efforts will be made to reach the broadest cross-section of the public.

Participants in the meetings will be invited to comment on the project design, on its potential environmental impacts and their mitigation, and on any alternatives which they consider should be investigated. Consulted persons are to be regarded as an invaluable source of local knowledge and will be asked about any information they have on the local area and on any special local issues.

Reponses to most questions are expected to be provided at the meetings. For certain questions, informal follow-up by telephone or e-mail maybe appropriate. The views expressed in consultations will be recorded. All responses will be collated and analysed. Meeting summaries will be published on the project website after the meeting.

Trans-boundary Communication

The GoA will forward the full project documentation to the IAEA headquarters in Vienna and make sure to request that the intent to build a new power unit in Armenia is communicated to the neighboring countries.

The Steering Committee's address, telephone numbers and e-mail address will also be communicated internationally so that the experts could receive communication from third parties abroad.

13.4.3 PCDP Documents

For the purposes of planning and implementation of the PCDP activities, the Steering Committee will have at its disposal the following documents:

- The Initial Planning Study; and,
- The project Environmental Background Information Document.

On the basis of these documents, the experts will be able to develop the elements necessary for organizing the activities listed above. Examples of such communication documents are:

- Fact sheet on benefits of nuclear energy;
- Brochure on the Armenian nuclear power project;
- Text of a newspaper announcement of the project;
- Text of a radio announcement of the project;
- Scenario of a TV advertisement;
- Etc.

13.5 INDICATIVE SCHEDULING OF THE PCD PROCESS

The Public Consultation and Disclosure process will start as soon as the initial planning studies and environmental background information document for the new nuclear power plant are prepared and ready for circulation. It will last up to the beginning of the construction period. The PCDP implementation is planned to coincide with the Environmental Impact Assessment process to maximize the effect of synergies of efforts in public communication. Indicative schedule of the PCD process is shown in the diagram that follows.

Indicative Scheduling of the PCD Process

<table>
<tr><th>Planning studies completed</th><th>PCDP Steering Committee established</th><th colspan="7">PCDP Activities Implementation</th><th>Start of construction period</th></tr>
<tr><td rowspan="6"></td><td rowspan="6"></td><td>Project show room opened to public</td><td>Interactive website launched and functional</td><td colspan="3" rowspan="3">Advertisements on TV and radio</td><td colspan="2" rowspan="3">Roundtable discussions on TV</td><td rowspan="6"></td></tr>
<tr><td rowspan="2">Telephone hotline established and functional</td><td>Notices in local areas posted</td></tr>
<tr><td>Initial announcements in national and local newspapers</td></tr>
<tr><td rowspan="2">Measures for trans-boundary communication taken</td><td rowspan="2">Leaflets and brochures developed and distributed</td><td colspan="5">Public meetings with experts held on a regular basis</td></tr>
<tr><td colspan="5">Feedback collection and processing</td></tr>
<tr><td colspan="7">Environmental impact assessment process</td></tr>
<tr><td>Month</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td></tr>
</table>

14. EVALUATION OF THE NEED FOR AN OWNER'S CONSULTANT

The principal objective of this section of the study is to define the construction roles, responsibilities, and capabilities of the Government of Armenia organization (the owner) that will become the owner of the new nuclear unit. Also discussed is the need for consulting support to this organization. The tasks, capabilities, and qualifications of the owner's Consultant as well as the estimated cost should be defined in this study. The study assumes that the Government of Armenia will be the majority owner of the facility and when the report refers to the owner's organization, it is referring to the Government of Armenia organization that will serve as its representative during construction of the plant. As such, it will have the role often served by the parent utility company in other countries. The report is not intended to address the organization that will operate the plant after construction. However, some reference is made to this organization since it will begin to develop and have a role during the final phase of construction.

14.1 ORGANIZATIONS INVOLVED IN A NUCLEAR POWER PLANT PROJECT

There are three basic contract approaches that have been used for NPP projects; a turnkey project, a split contract or a multi-contract.[69] In a turnkey project a single contractor takes responsibility for nearly the entire project. In a split contract the responsibility for the project is divided among a small number of contract organizations, each organization has clearly defined responsibilities. In a multi-contract the utility or, more likely, the utility's architect /engineer, has overall responsibility and discharges this responsibility through many separate contracts. In fact, it is often difficult to establish absolute distinctions; actual turnkey projects always show some aspects where other contractors and the owner have primary responsibility.

Even in the case of a turnkey project, numerous organizations are involved in the construction of a nuclear power plant. As an example, the construction of Teollisuuden Voima Oyj's (TVO) Olkiluoto 3 nuclear power plant in Finland is a turnkey project with Areva serving as the supplier, the utility TVO is the owner.

In spite of the fact that it is a turnkey project, TVO is required to maintain a high profile within the project. In 2006 the regulator, the Finnish Radiation and Nuclear Safety Authority (STUK), appointed an inspection team to review the construction project. The team found that TVO needed to enhance its presence at the site and recommended; "In spite of the turnkey delivery, TVO is ultimately responsible for the safety of the power plant and that this responsibility cannot be assigned to a supplier on the terms of a purchasing agreement."[70] Even without the involvement of the regulator, investors and lenders need to see an experienced, qualified, and creditable organization involved in managing the project

A few items should be noted here:

1. The owner retains overall responsibility for the project. To fulfill this responsibility properly the owner must have an organization of sufficient size and experience to prepare bid documents, and monitor the planning, design, construction and testing of the plant.

2. The vendor only provides the initial core. The owner must provide subsequent fuel loading.

[69] IAEA-TECDOC-1513, Basic infrastructure for a nuclear power project, June 2006
[70] Insufficient guidance of subcontractors' work in Olkiluoto 3 nuclear power plant project, STUK Report December 7, 2006

3. The owner sometimes has significant construction responsibilities, particularly civil construction.

4. Overall project management requires expertise in planning, scheduling, and construction management.

5. Technical expertise in all phases of the project is needed to successfully manage the licensing activities and prepare documents for the regulator.

Nuclear construction projects go through several organizational phases as the project moves from concept, through construction to operation. Normally the project is divided into phases as follows:

- Planning phase-This includes; development of a conceptual design, preparation of major contracts, development of plans and schedules.
- Construction execution phase- This includes; civil construction, bulk electrical and mechanical installation, installation of control systems. During this phase, the owner will also be responsible for oversight of design decisions, licensing authority interface and ensuring effective quality assurance and control for design and construction.
- Testing phase-This includes; initial operation of equipment, component tests and system startup testing.

Throughout these phases the role of the owner's organization will change from an organization that is evaluating contractor capability, to one that is monitoring contractor performance, to one that is preparing to pass responsibility on to the operating staff. In each phase there is a different focus; at first a heavy focus on contractual issues and project planning, then a focus on execution and schedule and finally a focus on construction completion, procedure preparation, training and operation of integrated systems. During each of these phases, the owner will continue to have ultimate responsibility for the safety of the nuclear plant.

The variety of roles requires that many different skills be resident in the owner's organization and the distribution of skills evolves and changes throughout the project.

14.2 GOVERNMENT OF ARMENIA MANAGING ORGANIZATION

The purpose of this section is to describe the role of the GoA Managing Organization, the owner, in the three phases of the new nuclear project. The size and duties of the owner's organization will be determined, in large part, by the type of contractual approach applied. In the case of Armenia, it is assumed that the desired arrangement is a turnkey project. Regardless of the type of project selected, there is a strong need for the owner to maintain a well staffed project organization to ensure that contractors and suppliers are meeting their commitments, to interface with the regulator and to prepare for eventual operation of the plant.

As was observed in the case of TVO, even for a turnkey project, there are several direct responsibilities that normally fall to the owner. The exact nature of these responsibilities varies from project to project; however typically these direct responsibilities are:

- Site preparation and clearing
- Bulk excavation
- Water and power supply
- Roads and/or harbors
- Construction and operation of the town site,

- Civil structures for cooling water system
- Supply of commissioning and operation staff for training

So the owner organization has some or all of the direct responsibilities listed above. In addition, the owner has the responsibility of preparing bid documents, evaluating and selecting bidders, project management (including financial management), review of the suppliers design, schedule review, industrial safety, quality assurance, oversight of construction, plant licensing, fuel supply arrangements, preparation of the emergency plan, and preparation of operating procedures.

A major task is the preparation bid specifications, requests for quote, and evaluation of bids. This activity requires a combination of technical, commercial and financing expertise and can benefit from engagement of an international consultant to coordinate the technical part of the specifications. The utility undertaking the task of implementing the nuclear project should acquire adequate knowledge of the bidding process and technology assessment as well as sufficient funds and human resources to carry out the task. The utility for this purpose should develop in house resources and engage expert consultants in all areas of customer/supplier interface. The consultant selected should have experience in all technologies for which proposals are requested."

The bidding process is complicated and requires a staff with a high degree of expertise in commercial and technical matters. Second, the services of an experienced consultant are desirable if the owner has limited experience in bidding and constructing nuclear plants.

Project management capability is required to successfully manage the design, licensing, construction, testing and operation of the nuclear facility. The expertise required within the project management organization includes; financial management, planning and scheduling, quality assurance (QA), equipment and materials supply, field engineering, construction and installation, and commissioning.[71] In many of these areas the responsibility of the owner is to review the performance of the main contractors; however the same degree of experience is required of the owner if the review is to be done successfully.

Industry experience demonstrates that timely completion of nuclear projects requires the design be completed prior to starting construction. This allows construction to proceed without delays caused by lack of design information. It also promotes lower costs by reducing the number of change requests, one of the major causes of cost escalation. The owner plays an important role in this effort through review of the design prior to contract award to ensure it is complete and by monitoring design change requests during the construction project. To carry out the owner activities related to nuclear plant design review, the owner will need some experience with nuclear plant design, process system design, piping analysis, control and instrumentation, structural engineering, radiation shielding, and human factors

The supplier will develop a quality assurance manual and program for the construction project, but the owner will need to audit the program and its implementation. Furthermore the owner will need to develop the operational quality assurance program that will go into effect following construction.

Typically, the supplier only provides fuel for the initial core; subsequent fuel was the owner responsibility. Normally the owner purchases uranium and fuel services directly. These activities

[71] ibid

involve significant expenditures and the ability to plan and execute the best management of assets. Operating procedures and the emergency plan, even if the main contractor provides the basic documents, need to be formatted and adjusted to meet the requirements of the owner.

These are some of the major responsibilities and activities of the owner. In the following paragraphs how these activities change through the project will be discussed. As discussed below, when the owner organization activities change, the skills required within the owner's organization will also change.

14.2.1 Organizational Structure during the Planning Phase

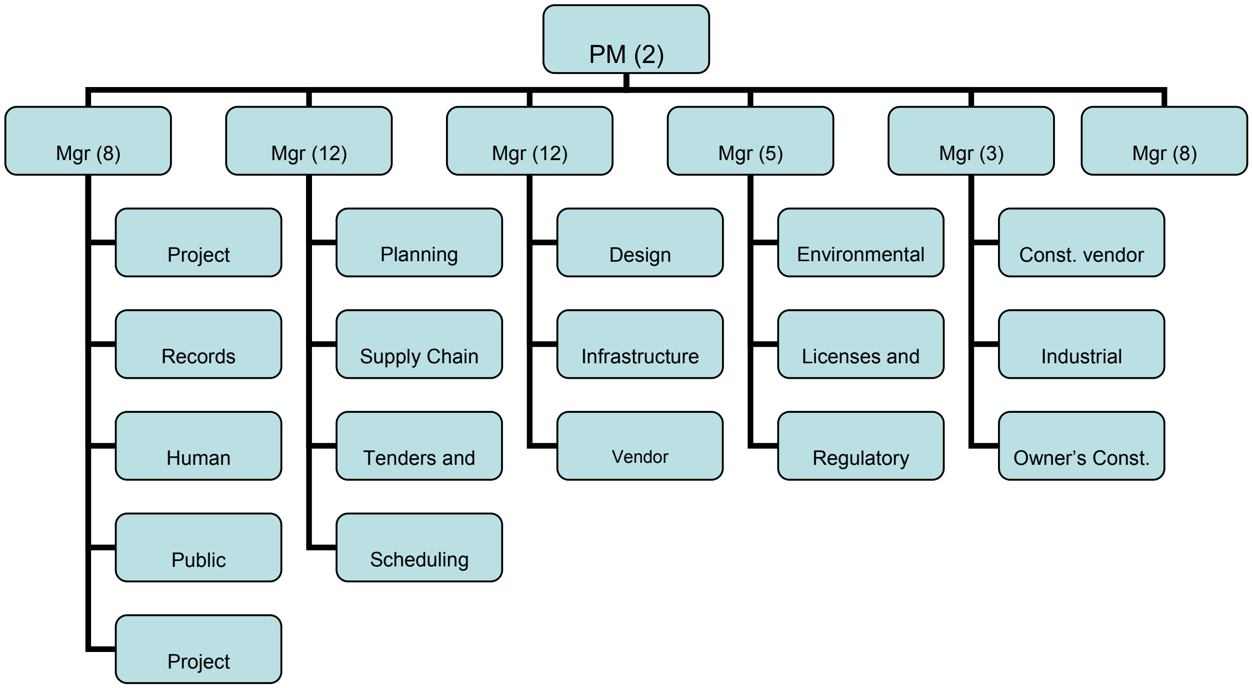
In the planning phase, strong emphasis is placed on the preparation of bid packages, review of bids, negotiation, licensing and award of contracts. These documents cover legal, technical, financial, commercial, scheduling, change control and regulatory issues. The people representing the owner need to be expert in these areas.

A typical organization that serves the required functions could be one that groups these responsibilities into six sections.

1. Support
   project controls, records management, human resources
2. Development
   Material management, Planning, Scheduling & Budget Control
3. Engineering
   design control, Infrastructure design, vendor technical review
4. Licensing
   Environmental, Licenses and permits, Regulatory Interface
5. Construction preparation
   Preparation for construction vendor oversight, Industrial Safety, Owner's construction responsibilities
6. Quality
   Quality assurance

A chart of this organization is shown in figure 14.1. As pictured, this yields an organization that covers the necessary functions, provides sufficient managerial focus on each activity and provides independence for the quality assurance organization. The approximate staffing for each section is shown in parenthesis and the total staff size is 50.

Figure 14-1, Organization during the Planning Phase



The focal points during the first stage of the project are; developing tenders and contracts for the work, reviewing the technical capabilities of the vendors, developing and filing reports for necessary licenses particularly in the environmental area, and designing the infrastructure that is part of the owner's responsibility. In this organization the majority of the staff is devoted to these functions.

Contract negotiations range over technical, commercial and financial aspects of the project. Normally, the technical and commercial contracts should clearly identify the scope of the work of the supplier and the owner, schedule, price, performance parameters, warranties, rights and obligations of the owner and the supplier, and mechanisms of reviews, adjustments, approvals and dispute resolution. Particular attention needs to be paid to the price structure, change orders, performance guarantees, limitations on liability, liquated damages, liability, indemnification and termination rights. Arrangements for financing will need to be completed with the project equity holders, lending agencies and those organizations purchasing a portion of the electrical output.

Properly prepared contracts can protect the financial health of the owner and expedite construction of the facility. Development of good contracts requires expert people. If the owner selects an experienced consultant early in the process; the consultant can assist with these activities. Concurrently the owner needs to be involved with designing and preparing to construct those facilities which are in the owner's scope. Failure on the part of the owner to finish their part of the work in accordance with schedule could lead to delays and charges to the owner under the contract. Often the owner will select a consultant who has been through all phases of nuclear plant construction. Such a consultant can advise the owners on contractual, technical and regulatory issues.

14.2.2 Organizational Structure during the Construction Execution Phase

Once construction has begun, the focus of the project will change. In this phase the owner's organization will pay particular attention to; developing an accurate schedule, actual performance versus the schedule, identification of areas that did not meet the schedule, restraints, and development of and execution of recovery plans.[72] The organizational structure will need to grow and evolve to meet these needs.

As shown below, the organization at this phase has grown to 194 people. The primary changes have been:

- Expansion of the planning and scheduling function.
- Expansion of the licensing and quality functions
- A group of engineers to perform the liaison function with the architect/engineer and the main contractor.
- A group to provide oversight of the construction contractor.
- A group to supervise the construction of those facilities within the owner's scope of responsibility. In this area the owner often acts as general contractor over a group of subcontractors doing the work.
- Adoption of a security organization to look after construction security.
- Addition of a reactor fuel group to begin assisting and monitoring the fuel vendor and to purchase fuel and fabrication service.

A chart of the construction phase organization is shown in Figure 14.2. While this may seem to be a large organization, but it is necessary to ensure that the owner's scope of work is accomplished according to schedule, to minimize change notices from the contractor, to monitor progress against the schedule and to maintain accurate financial and technical records of the project. The added resources also provide the necessary presence consistent with the owner's responsibility for safety.

Implementation of the QA program is the task the Constructor, Architect/Engineer, and the suppliers of nuclear equipment. However, the owner organization must review and approve the QA Programs and audit the implementation activities by all of the contracted organizations. The owner organization will probably need QA auditors, certified to ANSI N45 or ISO 9001 standards

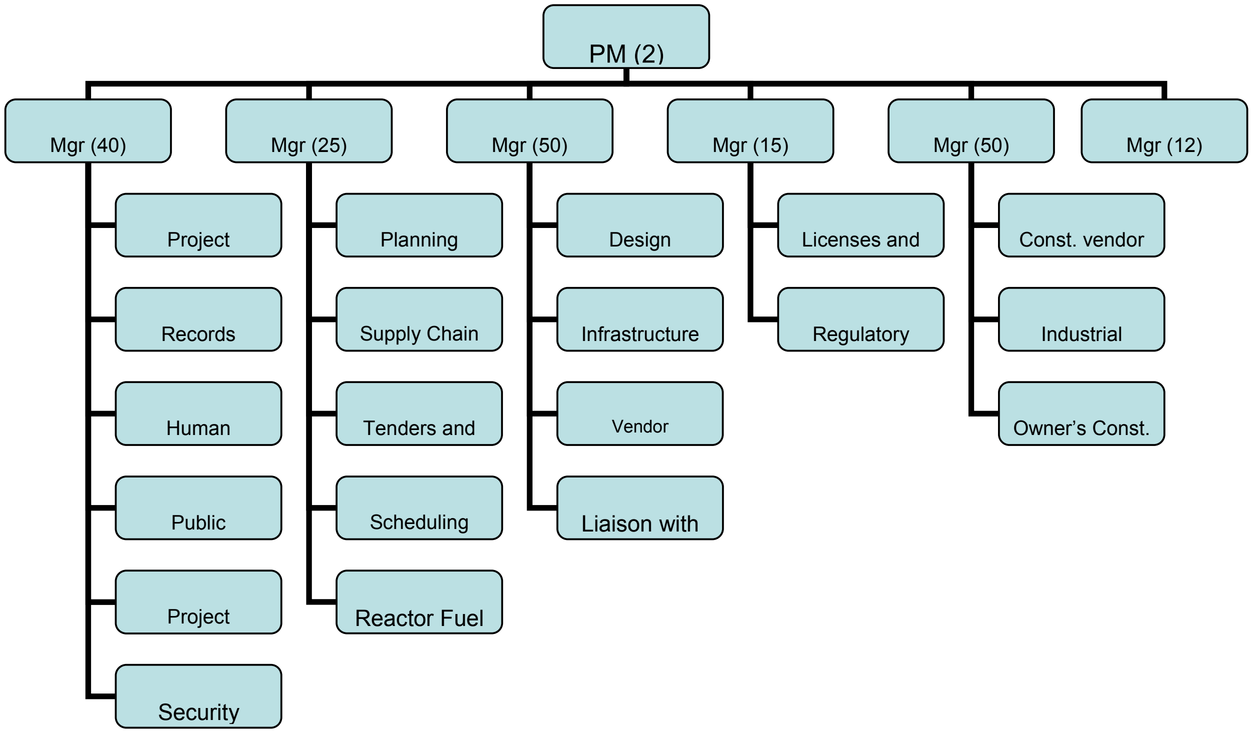
During the construction period, the owner should also begin to prepare for operation of the plant. To do this the owner should start to hire the people who will operate and maintain the plant. Training should begin on plant systems and procedures should be written for operation and testing of the plant. To staff just the operating shifts will require 6 shifts of 3 to 5 licensed operators; all receiving 12 weeks training on a simulator similar to the plant. Procedures should be written by those who will use them, with assistance from the A/E. Development in these areas paves the way for the final phase of the project, testing. As the testing phase approaches a new organization comes into being, normally headed by the prospective plant manager.

As the construction contractor completes work on a system, full responsibility for the system is turned over to the startup organization, a separate wing of the main construction contractor that

[72] Guidelines for Nuclear Power Station Construction Projects, INPO Guideline INPO 86-023

individually tests each component in the system and then performs integrated tests on the system. At the completion of testing the system is capable of operation. In some cases the completed system is needed to support further construction; for example ventilation systems, water systems and electrical systems.

Figure 14-2, Owner's Organization Construction Execution Phase



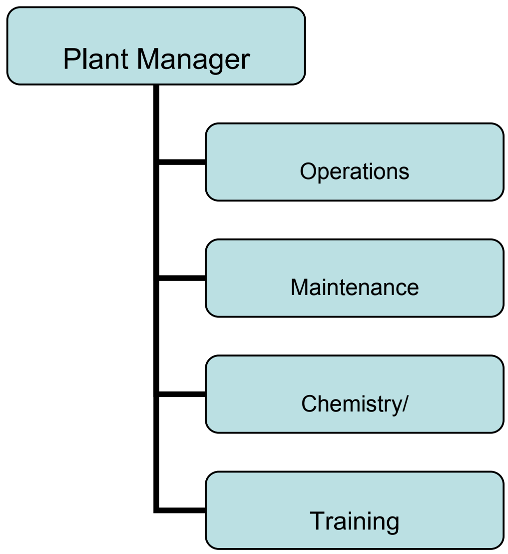
14.2.3 Organizational Structure during the Testing Phase

On a turnkey project, startup testing and initial operation remains the responsibility of the construction contractor. However, the owner must have the licensed personnel for operation of primary systems after the core is installed, and for all operations associated with initial criticality and subsequent operation of the plant. The testing phase offers the opportunity for the owner's organization, the eventual operators of the plant, to gain experience with plant systems. Some projects have taken advantage of this opportunity by seconding engineers and operators to the construction contractor for the purpose of participating in startup testing and initial operation. This practice is recommended for Armenia.

The tasks of participating in startup testing and operating systems to support construction requires that people be hired and trained for these roles. In preparation for the testing phase, the owner organization should begin to staff the operations organization. It is important for these people to be trained on the design of plant systems and begin development of plant procedures.

During testing, construction is still ongoing so the owner needs the organization shown above for construction phase activities. In addition a new preoperational organization to support testing and operation begins to be formed. Early activities for this organization involve training and procedure preparation. Later individuals from this organization are seconded to the construction contractor to participate in startup and initial operation. As mentioned above, staffing for the operating shifts will require 18 to 30 licensed operators. The testing organization typically consists of 60 to 80 technicians and engineers.[73] Later, when the plant is turned over to the owner, all these people will return to the operating organization with detailed knowledge and experience on the plant. This preoperational organization is shown in Figure 14.3.

Figure 14-3, Additional Preoperational Organization during Testing Phase



When the plant goes into full operation a larger and more complex operating organization is required. It is not the purpose of this report to develop that organization; however people from the testing phase organization should fit neatly into the organization developed for the operating plant.

14.3 TRAINING OF THE OWNER'S ORGANIZATION

In order to fulfill its project responsibilities, the Government of Armenia Managing Organization will need to receive training in a number of crucial areas. Assuming the people hired to work in the organization have the basic skills for their position, they will require training on the unique tools and activities that are part of the project. These areas include; project scheduling and control software, the designer's document system, maintenance of digital control systems, specific design attributes, operation of plant systems and procedure development and control.

For administrative tools like the project scheduling system, the designer's document system and the procedure control system, the respective vendor will provide training on the software that is provided. This training should consist of general training for all users and specialized training for the owner's personnel who will be responsible for proper functioning of the system. In the case of plant systems and equipment, the equipment supplier will provide training on the operation, testing and maintenance of the systems and equipment. In most cases the owner will want to have in house training personnel participate as students in the initial training and then, using the materials supplied by the vendor, develop and present the training to other of the owner's

[73] Construction of Nuclear Power Plants, A Workshop on the Nuclear Energy Renaissance, Robert E. Uhrig, Athens May 8, 2008

personnel after the supplier has finished his work. In this way the information can be passed on to other staff members long after the original supplier leaves the site. For this reason it is important for the owner to build a training organization during the construction and testing phases of the project. Training in the area of construction quality assurance will also be needed. If an owner's consultant is employed, this organization can provide the necessary training in this area.

14.4 CONSULTANT TASKS

Depending on the planned staffing of the GoA Managing Organization, support from international and local consultants may be needed to perform some of the activities during all phases of the project. Such support is strongly recommended by the IAEA. In addition to ensuring technical and management expertise, the owner's consultant can provide assurance to investors and lenders, which need to see an experienced, qualified, and creditable organization involved in managing the project. This section will evaluate the need for consultant support to the GoA Managing Organization during each of the phases.

Typically the organization owning the plant, in this case the Government of Armenia, staffs the organization such that senior managers are permanent employees, but the only other permanent employees in technical or working level positions are those who can easily move on to positions in the operating staff of the plant. Many of the skills needed in the owner's organization during construction do not fit well in the operating plant and are good candidates for consultant support. In addition, the owner's organization may lack experience in some areas and a consultant could be used to assist the owner and provide hands on training to the owner's employees while they build experience.

During this time, the owner is most interested in developing the staff that will operate and maintain the plant. For this reason the owner tries to use permanent staff in those areas where they can gain valuable experience. In particular these areas are:

- Security
- Supply chain
- Reactor fuel
- Design control
- Regulatory interface
- Startup testing
- Operations
- Chemistry/Radiation Protection
- Maintenance
- Quality Assurance/Control

A consultant with strong nuclear construction experience serving as an advisor to the owner is instrumental in protecting the owner's interests during construction of the plant. Such a consultant should have expertise in contract administration, design review, planning and scheduling, quality assurance and have the ability to monitor the construction effort. Several companies exist that can provide this service. The level of effort required will change with the development of the project. At first only a few people, 5 or 6, will be required to assist with development of the request for proposals. More will be added during the review of proposals and negotiations of contracts. During the construction phase the consultant staff will reach its largest size and then gradually diminish as construction is completed and operation begins.

14.5 QUALIFICATIONS AND CAPABILITIES OF THE OWNER'S CONSULTANT

This section will describe the necessary capabilities and qualifications of the consultant organization(s). Particular areas where consultants are heavily utilized are:

- Project controls
- Project finance
- Records management
- Planning and scheduling
- Tenders and contracts
- Infrastructure design
- Vendor technical review
- Liaison with the A/E
- Licenses and permits
- Training program development
- Construction vendor oversight
- Owner's construction responsibilities

While the owner will need some people with these skills during operation of the plant, many more people with these skills are needed during construction than are needed during operation. Clearly the consultant needs to be well versed in the areas listed. Specific requirements for the organization serving as the owner's consultant are:

- significant experience in construction of nuclear facilities,
- detailed knowledge of nuclear plant design requirements and practices,
- experience in scheduling and managing nuclear construction projects,
- demonstrated experience in applying modern construction management tools,
- Capability to assist the owner with licensing and environmental permits.

There are a number of consulting and engineering firms that have participated in other nuclear construction projects who could fill this need. Such firms have used modern scheduling tools and they have been deeply involved with project controls and finance. In addition they have good experience in developing bids for the work involved in the project. Since many of the supplier and contracting organizations will be from outside Armenia, legal representation with strong international contract experience is required.

14.6 CONSULTANT LEVEL OF EFFORT AND COST

This section will estimate the level of effort and costs for consultant support and other resources.

Under this scenario, the consulting organization would start with 5 people and expand to 25 by the beginning of construction. At the peak of construction, the consultant could employ as many as 40 people. It is important to note that for the most part these people would fill roles in the owner organizations shown above. The remainder of the organizational slots would be filled by the owner's own personnel who would stay on with the operating organization.

Assuming that the construction period is 72 months[74], and the consultant starts work 18 months prior to the beginning of construction, and the average annual cost of one full time equivalent person is $200 k; the annual expenditure for the consultant would be:

Year	Consultant Cost
1	$1000 k
2	$3000 k
3	$6000 k
4	$8000 k
5	$8000 k
6	$8000 k
7	$8000 k
8	$6000 k

14.7 CONCLUSIONS

Several important conclusions can be made about the role of the Government of Armenia's role in managing the construction of the proposed ANPP 3:

- Even for a turnkey project the ultimate responsibility for the project lies with the owner of the plant. The owner's ultimate responsibility for nuclear safety cannot be delegated or contracted
- The GoA needs to establish a Managing Organization to perform the activities of the preparation and planning stage and interface with the construction and operating organizations during subsequent stages.
- Many areas of expertise are required within the Managing Organization.
- A consultant can provide significant experience and capabilities that may not be available in the GoA Managing Organization.

[74] Meeting with Westinghouse representative, August 2008

15. INTERNATIONAL TENDER PLAN

15.1 DESCRIPTION OF TENDER ACTIVITIES

Sequence of Activities

- **Law on Nuclear Energy**
- **Establishment of the Tender Committee and the Working Group**
- **Selection of the contract approach**
- **Domestic participation (for some construction or supply works)**
- **Preparation of the bid invitation specification (BIS**) (*Multiple package NPP scope*)
- **Request for Expression of Interest (EOI)**
- **Prequalification of bidders** *(Financial capability and technical qualification, Short-listing*)
- **Tender Solicitation and Bidders conference**
- **Distribution of (BIS) (***Bids submitted in the closed envelopes***)**
- **Submission of bids**
- **Evaluation of bids** *(Technical, including fuel, financial, technology transfer evaluation)*
- **Contract negotiation and conclusion**
- **Change orders**

Law on Nuclear Energy

To support construction of the new nuclear unit huge investments are needed.
At the same time such an undertaking requires substantial measures of security. So Armenia first of all should prove its commitment to protect and guarantee public safety and security through:

- Establishment of an independent body to develop country's nuclear program; and,

Development of a new Law on Nuclear Energy, adoption of which is even more ***Establishment of the Tender Committee and the Working Group***

Establishment of the Tender Committee and the Working Group under the Committee that would evaluate and carry out activates related to construction of the new unit will be done by a special RoA Governmental Decree.

The Committee should comprise representatives of: the Ministry of Energy and Natural Resources, the State Committee for Regulation of Nuclear Safety (SCRNS), the Ministry of Justice, the Ministry of Economy, the Ministry of Finance and Ministry of Emergency Situations, the Public Services Regulatory Commission, the Water Resource Management Agency and other involved governmental agencies.

The Working Group will be the standing body of the Committee. It will have to carry out all operational activities of the Committee aimed at preparation of bid invitation specifications (BIS), prequalification of bidders and evaluation of bids, tender solicitation and conclusion of contract. The Working Group should have highly qualified legal and financial experts, engineers and energy sector specialists experienced in the corresponding areas. The Working Group may also include international advisors and experts in the field of nuclear regulation, safety, security, non-proliferation and waste management.

Selection of the Contract Approach

Depending on the contractual approach, the scope of economic evaluation of bids may vary significantly. Three main types of the contracts that usually applicable to the NPPs are:

1. Turnkey contract (a single contractor or a consortium takes responsibility for completing the whole project, all phases of the project design and construction);

2. Split package contract (overall responsibility for the project implementation is divided among different contractors responsible separately for the large components, sections of the project, etc.);

3. Multiple package contract (the owner is responsible for the project design and implementation; numerous contracts are concluded with different contractors to carry out parts of the project). The plant is delivered to the owner at the end of construction and acceptance testing.

4. Along with that, international practices allow application of build, own and operate or build, own, operate and transfer modes. In this case the plant's ownership deviates from the contract approaches described above, because a foreign investor has to plan, construct, operate and provide the financing for the NPP. This investor must also carry the risk over entire plant life, or part of it. These contract approaches are similar to the turnkey contract, except that the major difference in the ownership of the plant over all or a part of the plant's life.

The choice of contractual approaches for the NPP is one of the key decisions to be made before preparation of BIS. Decisions must also be made on how the project management, construction and commissioning management, as well as plant operation should be organized. Selection of the type of contract will fundamentally affect the key aspects of projects implementation. The desired contractual approach must be specified in the BIS.

The kind of contractual approach to be adopted for a particular project can only be determined once all the factors have been carefully evaluated. The balance of advantages and disadvantages for a given project can be judged if a project approach study is carried out. The project approach study can be accomplished in parallel with the studies of domestic participation. The main factors to be evaluated are:

- The national nuclear policy;
- Domestic participation policy and plans for development of local engineering and industrial capacities;
- Availability of qualified project management and engineering personnel;
- Existing engineering and industrial infrastructures in the owners' country and capability to build local supporting infrastructure;
- Ability to set and maintain a BIS preparation and bid evaluation schedule;
- Plant owner's experience with similar projects;
- Plant design criteria and engineering features;
- Economic consideration and financing prospects;
- Warranty and liability considerations.

Domestic participation

Only limited domestic participation can be expected during the construction of the new nuclear unit. Thorough research of existing capacities should be carried out to find out available capacities and to make precise assessment of the domestic participation that would significantly reflect on the cost of the project. The Government of Armenia is in the process of preparation of Assessment of nuclear manpower needs for the trainings within the scope of the tailored project with the IAEA. That assessment may contribute to evaluation of domestic resources and provide measures to enlarge and improve these resources.

The share of domestic participation could be one of the main criteria for the bid evaluation. With regard to domestic participation in the field of engineering, manufacturing, construction and quality assurance, the proposals have to be assessed on a case-by-case basis. The share and scope of domestic participations, as well as goals and incentives should be provided by the BIS.

In most cases, an industry-wide survey must be undertaken by the different suppliers in order to assess the present and the potential industrial capabilities of the country for the manufacture of the NPP components, as well as for development of the local infrastructure for construction of the nuclear unit. The results of this survey may form the basis of the proposals which will be evaluated in the bid evaluation process.

It is also recommended to develop a minimum domestic participation program that would cover the following subjects:

a) Involvement of domestic staff in the project management and operation;

b) Implementation o f quality assurance procedures, nuclear regulations and licensing issues;

c) Safeguards and physical protection;

d) Site preparation and construction of some plants buildings and structures;

e) Planning and coordination of O&M personnel.

The incentives and expected percentages of domestic participation should be clearly defined. Bonuses and penalties for the domestic participation in the bid evaluation should indicate the importance of these activities. Along with that, training programmes have to be developed, particularly in the areas of engineering and manufacturing in order to support adequate level of domestic participation.
One of the most important components of supply capability is respective technology and know-how for design and manufacturing If the technological processes and quality assurance can not be applied from the country's own experience, these activities should become part of the technology transfer programme.

Preparation of the bid information specification (BIS)

Preparation of BIS is one of the most important steps in the tender process. These specifications should be as complete and comprehensive as possible to provide the bidder with necessary information and data for bid preparation. BIS explain the organization of the entire project, i.e. what the project's sponsor wants to buy.

The BIS address the following issues:

1. Detailed site description;
2. Subject of BIS, project time and schedule;
3. Types and sizes of reactor and its application;
4. Technical and electric grid requirements;
5. Fuel strategy and import requirements;
6. Scope of supply and services desired, owner's scope of supply;
7. Scope of domestic participation;
8. Technology transfer;
9. Safety requirements, nuclear liability, guaranties and warranties;
10. Bidding conditions, administrative instructions and bid evaluation criteria.

Ambiguous or incomplete BIS documents force potential suppliers to make their own assumptions as to what is required, which often leads to higher process costs.

Request for Expression of Interest (EOI)

After preparation of BIS, potential suppliers should be contacted to provide an expression of their interest in submitting proposals for the project. The request for EOI could be based on preliminary BIS, with the final BIS prepared after qualified bidders are identified. The request for the EOI should include a description of the intended technical and financial approach to the project (including type of reactor, technical specification, form of contract). The request should also require that interested parties provide their full contact information and a preliminary indication about their participation (EOI) in the tender no later than the deadline set out by the Committee. The request for EOI may also request that interested bidders provide information on their qualifications, experience, and financial standing for use in the prequalification process.

Prequalification of bidders

Prequalification of bidders includes demonstration of their financial capability and technical competence. Usually, provision of references or data on successful implementation of a similar project is required as well. For prequalification of bidders, a questionnaire can be developed and send to the bidders. After prequalification, the BIS and a request for bids should be distributed to the qualified bidders.

In the supplier's countries, the development status of the advanced plants that may be offered varies considerably and may not include operating experience, However, when a reference plant is requested in the BIS, the design requirements often ask for the application of proven design and components in order to take advantage of extensive commercial operating experience. Consequently, a detailed specification of the reference plant states what the owner needs to fulfill regarding its goals and objectives and what it wants to receive with the bids must be included in the BIS.

Distribution of BIS

After review of EOI and prequalification of bidders the BIS should be finalized and delivered in a paper copy to each pre-qualified bidder by courier.

The Tender Committee also has to establish an electronic Data Room at a secure website address for further distribution of documents, provision of various types of background information and receipt of documents from the bidders. The Tender Committee may add, delete or amend documents in the Data Room at any time. The bidders are responsible to ensure access to the Data Room and to acquire software that would allow to download and to place information from and into the Data Room.

Tender Solicitation and Bidders Conferences (Meetings)

A. Tender Solicitation

During the tender solicitation process the Tender Committee may:

1. identify the highest ranked bidder and either accepts the bidder's Proposal as submitted or enters into negotiations with that bidder;

2. identify the two highest ranked bidders and enters into negotiations with first one and after failing, with the second one;

3. enter into separate and distinct but contemporaneous negotiations with the first and second bidders and identify the preferred one.

The bidders may notify and ask for clarification about any ambiguous or inconsistent terms or condition in the tender documents by the deadline set in the Timetable for submission of requests for information.

If there is a conflict or inconsistency between the electronic version of the BIS and the hard copy, or any other version of the same BIS document (electronic or hard copy), the version placed in the Data Room should govern.

If there is any conflict between the versions of the tender documents placed in the electronic Data Room, the document of the later date should prevail. The date of the document is determined by the date and time when the document was placed in the Data Room.

The bidders are allowed to submit questions or requests for information (RFI) categorized as follows:

a) RFIs that are of general application and that would apply to other bidders as well;

b) RFIs that the bidders consider to be commercially sensitive or confidential.

If the Tender Committee disagrees with categorization of the RFI, it may either give the bidder an opportunity to categorize the RFI as a General RFI or withdraw it. If the Tender Committee at its sole discretion determines that the RFI submitted by the bidder as Confidential is of general application, it may issue a clarification to the bidders dealing with the same subject as the withdrawn Commercially Confidential RFI. If the Tender Committee agrees with the bidder's categorization of a Commercially Confidential RFI, it should provide a response only to the bidder that submitted the RFI.

The responses to the RFIs are not part of the tender document and do not amend the BIS. If the RFI requires amendment of the BIS, such an amendment can be made only by the decision of the Tender Committee before the set Submission Deadline.

The Tender Committee may use the negotiation process to negotiate any aspect of the proposal, the Contract, or any amendment to the Contract that is required to revise the scope of the project.

B. <u>Bidders Conferences</u>

Except for communications which occur in the Bidders Conference and Commercially Confidential Meetings, the bidders shall submit all questions (requests for information) and other communications regarding tender documentation and tender procedure to the contact person named in the BIS Data Sheet. The questions and other communications shall be submitted to the contact person in hard copy.

The Tender Committee convenes Bidders Conferences on the dates and at the times set out in the Timetable. The Working Group should inform the bidders on the location of the meetings by letter. While attendance at a Bidders Conference in not mandatory, the bidders are strongly encouraged to attend. A bidder's failure to attend is at the bidder's sole risk and responsibility.

Participants of the Conference may ask questions and seek clarifications on any issues related to tender documents and procedure. Oral answers given to the bidders shall not be considered final, unless the bidder also submits those questions in writing and receives written responses from the Tender Committee.

The Tender Committee may also convene Commercially Confidential Meetings with individual bidders:

a) to discuss technical and commercial project issues;

b) to discuss preferred contract and amendments to it or any other technical or commercial issues related to the project, including licensing and scheduling issues.

The location of the Commercial Confidential Meetings shall be determined by the Working Group and the information shall be provided to the bidders prior to the meetings. The approximate date and time of the Commercially Confidential Meetings will be set out in the Timetable.

No statement, consent, waiver, acceptance, approval or anything else said or done at the Commercial Confidential Meetings by any member of the Government shall amend or change the provisions of the tender documents.

In order to ensure the meetings proceed in an efficient and effective way the bidders should be requested to submit materials and agenda items 5 days prior to each meeting.

Submission of bids

Based on the results of prequalification, the Tender Committee should prepare a list of participants of the tender. Only those included in the list are allowed to submit their bids.

The Tender Committee should be the single point of contact with the bidders.

Each bidder should submit one original and specified number of copies of Proposals to the Tender Committee before applicable deadline. The documents should be provided in hard and electronic copies. It is the sole responsibility of the bidders to ensure that the documents are received by the Tender Committee before the deadline. If there is a difference between the original document and the copy, the original as submitted in the hard copy should govern.

The bidder may withdraw the submitted documents only by giving written notice, before the set deadline.

Changes and amendments in the tender documents can be made before the set deadline through:

a) withdrawal of submitted documents before the set deadline with prior written notification of the contact person within the Tender Committee;

b) submission of revised replacement of the documents before the set deadline with prior written notification.

Except the cases provided above, each document provided by the bidders is irrevocable and remains in effect and open for acceptance, typically for up to 90 days after the set deadline.

Evaluation of bids

The main aspects of bids evaluation are economic and technical.

A. Economic Evaluation

The economic bid evaluation is based on NPP investment costs, nuclear fuel costs, operation and maintenance costs, results of technical bid evaluation, commercial and contractual terms and conditions, economic parameters, financing proposals, domestic participation and technology transfer (local investment costs for industry, training of staff, infrastructure development may be calculated separately) and the owners' costs.

With regard to economic bid evaluation, the IAEA accounting system, which allows identification of deviations in the scope of supply and services, can be applied. It should be borne in mind that level of detail in the bid evaluation greatly depends on type of contract, for example, much more detailed information will be provided for a multiple package contracts than for a turnkey project.

At the same time, issues related to safety and security aspects of the nuclear unit should be thoroughly discussed and evaluated, despite of the type of contract.

International best practices suggest evaluation of bids based on economic figure of merit, which requires analysis of:

1. Results of the technical bid;
2. Capital investment costs;
3. Nuclear fuels cycle costs;
4. Operation and maintenance costs;
5. Owner's costs;
6. Commercial and contractual terms and conditions;
7. Financing proposals;
8. Economic parameters;
9. Domestic participation and technology transfer;

10. Fringe benefits and spin-off effects;

11. Political and socio-economic aspects.

The responsibility for the bidding process lies with the project sponsor and should be performed by the sponsor's organization.

If the bid is prepared by a consortium, all vendors involved should be qualified separately.

B. Technical Evaluation

The technical bid evaluation helps to develop costs related to deficits or surpluses in material and services occurring when a bid is compared with the BIS or the reference bid (the most complete one). So, as a result, the technical evaluation should generate figures for technical deviations in designs presented in the different bids.

Usually, the BIS describes a certain type of NPP which can be easily compared with the plants described in the various bids. The bids will be based on a specific technology that is licensable in the country of origin and which follows the standards, requirements and technical specifications indigenous to that country. Consequently, cost adjustment will be required to reflect the differences in quantities of components and their installation. Cost information for these adjustments can be taken from the required cost data tabulated in the bids in accordance with the IAEA accounting system, which is capable of addressing a spectrum of capital costs, fuel cycle costs and operation and maintenance costs, from a complete NPP down to individual system or components. This system has a high degree of flexibility; it can be used with all types of reactors and various contract approaches. The IAEA accounting system includes operation and maintenance system, consisting of the costs of plant staffing, consumable operating materials and equipment, repair and interim replacements, purchased services and nuclear insurance, as well as taxes and fees, decommissioning allowances and miscellaneous costs presented by separate detailed accounts.

If the level of detail of the cost data does not allow direct utilization, the necessary cost information will need to be requested from the bidders. For successful comparison of different designs from a cost standpoint, the team members must have a high degree of technical experience as the technical differences must be identified first.

Another important aspect of the evaluation process is the impact of differences in the plant design and operating characteristics. It is one of the most difficult tasks in the assessment, since in-depth analysis of differences in such diverse items as:

- Safety requirements;
- Failure criteria;
- Redundancies and diversities in components and qualitative assessment results;
- Implications of measures against "beyond design basis accidents"; and,
- Probability figures for the occurrence of severe accidents;

should be performed.

With that regard, both quantities and qualitative assessments should be performed, all uncertainties should be revealed and an appropriate amount for contingencies has to be added to the capital costs.

Contract Negotiation and Conclusion of Contract

Terms and conditions of the contract, including an outline of a draft contract should be submitted by the project sponsor as a part of the BIS. It should contain a list of documents that are part of the contract, as well as the list identifying priority of the documents. These documents describe required equipment and services, supply schedules and process, as well as other general conditions.

Contractual conditions primarily should consider any exceptions or deviations from the BIS and assessment of their effects in terms of costs. If the cost consequences of differences in the scope and the significance of items or facts are clear, then cost adjustments are readily obtainable and a direct comparison can be made. However, if it is not possible to arrive at a quantitative cost figure, a qualitative evaluation is required. Such an evaluation should address issues related to financial status and capabilities of the bidders for similar projects, the sociopolitical and economic situations in the supplier's country, and the risks and advantages involved.

The boundaries of responsibility for the scope of supply and services must be defined in detail in order to estimate the risks involved. The commercial risks should also be clearly identified.

The contract, which is also a part of the bid includes:

1. Objectives and detailed scope of goods and services;
2. Responsibilities of the owner and the contractor;
3. Financing agreements, securities, taxation;
4. Prices, price escalation formula, payment plans;
5. Liability limits and penalties;
6. Confidentiality agreement;
7. Termination of contract;
8. Responsible project management team for the owner and contractor.

Length of cycle, burnup, and storage of spent fuel assemblies in the plant or in storage outside of the plant, reprocessing and final disposal issues should also be address by the technical proposal and contract.

Change orders

Amendments and supplements to tender documents can be made only before applicable Submission Deadline. No statement, oral or written made by the Tender Committee or the Working Group member(s), including the contact person shall amend the tender document.

If comments and suggestions made by the bidders while submitting EOI are acceptable and require a change of the BIS, the change should be implemented by Amendment to the BIS.

Changes, addition and modifications to the Project Contract can be made only to those parts of the Contract that are being indicated as subject to completion or finalization.

The preferred Vendor is allowed to make the following minor additions and modifications to the contracts with the Suppliers:

a) Changes, addition and modifications to those provisions that require insertion or addition of information relating to the preferred Vendor corporate and funding structure which are not inconsistent with the principles set out in the Project Contract;

b) Changes, addition and modifications to reflect the provisions of the Project Contract more accurately;

c) Changes, addition and modifications required to complete any provision of the Project Contract or its Attachments (Schedules).

15.2 RESPONSIBILITIES FOR TENDER ACTIVITIES

Responsibilities for tender activities lie with the Government of Armenia which through adoption of a special Decree should establish the Tender Committee, consisting of all involved government agencies and the Working Group, acting as a permanent body of the Committee.

Activities within the Committee and the Working Group should be led by the Ministry of Energy. Operation of these bodies should be supported by the state budget.

15.3 TENDER DOCUMENT CONTENT AND FORMAT

The Tender Documents are:

a) The Bid Invitation Specification (BIS);

b) Appendix 1- The BIS Data Sheet;

c) Appendix 2 - Submission Requirements and Evaluation Criteria;

d) Appendix 3 – Proposal Submission Forms

e) Appendix 4 – Financial Submission Form;

f) Appendix 5 - Contract (including all related Schedules, Appendixes and Attachments) as listed in the BIS Data Sheet

If there are any conflicts or inconsistencies among the terms and conditions of the documents comprising tender documents, with respect to interpretation of tender process and all competitive procurement matters, the BIS should prevail over the Appendixes.

A. *The Bid Information Specification (BIS)*

The Bid Information Specification will consist of the following sections:

Section 1- Introduction

1.1 Background and Project Description

1.2 General

1.3 Overview of the Project Implementation and Procurement Process

Section 2- The Tender Documents and Issuance

2.1 BIS

2.2 Conflicts and Inconsistencies in Documents

2.3 Representatives, Expression of Interest, Distribution of Documents

2.4 Data Room

Section 3- The Tender Process

3.1 The Tender Process Timetable

3.2 Questions, RFIs and Tender Documents Comments and Changes

3.3 Communications Restriction

3.4 Meetings with the Bidders and Bidders Conference

3.5 Visiting the Facilities

3.6 Bidders Team, Conflict of Interest and Ineligibles Team Members

3.7 Confidentiality of the Proposals

Section 4- Proposal (Form and Content Requirements)

4.1 Purpose and Form of the Document

Section 5- Submission, Withdrawal and Modification of the Proposal

5.1 Submission of the Proposal

5.2 Withdrawal of the Proposal

5.3 Modification of the Proposal

5.4 Proposal Irrevocability

Section 6- Evaluation, Clarification and Verification of the Proposals

6.1 Prequalification of the Bidders

6.2 Verification of Proposals

6.3 Steps in Evaluation Process

Section 7- Competition, Negotiations and the Identification of a Preferred Bidder

7.1 Evaluation Results and Negotiations

Section 9- Legal Matters

9.1. General

9.2 Special Circumstances

9.3 Applicable Laws and Limit of Liability

9.4 Licenses, Permits, Etc.

<u>Section 10- Notification and Debriefing</u>

<u>Section 11- Interpretation and Definitions</u>

B. ***Appendix 1- The BIS Data Sheet***

Reference	Item	Date
	Establishment on the Tender Committee	
	Preparation of BIS	
	• Issuance of the BIS • Data Room Accessible to the Bidders	
Corresponding Section of the BIS	• Request for Expression of Interest • Commercially Confidential Meetings	
	The Coordinates of the Contact Person and requirements to the documents (EOI) to be submitted	
Corresponding Section of the BIS	Prequalification of Bidders	
Corresponding Section of the BIS	• Distribution of BIS • Commercially Confidential Meetings	
Corresponding Section of the BIS	• Tender Solicitation and Bidders Conferences (Meetings) • Visits to the Site and Facility (*Name and location)*	
Corresponding Section of the BIS	Submission of Bids *Instructions to Submission of Bids*	
Corresponding Section of the BIS	Evaluation of Bids	
Corresponding Section of the BIS	Contract Negotiation and Conclusion	

C. ***Appendix 2 - Submission Requirements and Evaluation Criteria***

Section 1 General requirements

Appendix 2 outlines the submission requirements and the related criteria for evaluation of bids.

To facilitate the evaluation the Bidders should provide the Tender Committee with the information listed in Section of the BIS in the same order and under the same sections and headings as it is provided in the table under the Section 2 of this Appendix. The Bidders are advised to treat the sections set out in the submission requirements and evaluation criteria chart as a Table of Contents for their documents.

Although there is no fixed page limit for the documents to be submitted to the Tender Committee, the Bidders are strongly encouraged to limit their documentation to a maximum of single- sided pages.

Section 2 Categories of Evaluation

The Tender Committee will evaluate the Bidders in accordance with the following general categories:

	Category of evaluation	Evaluation results
1	Demonstration of capacity to prepare successful construction license application	Unsatisfactory/Satisfactory
2	Demonstration of a plan to address safety and security issues	Unsatisfactory/Satisfactory
3	Willingness and capability to deliver the project	Unsatisfactory/Satisfactory
4	Financial strength of an applicant	Unsatisfactory/Satisfactory
5	Legal position of an applicant	Unsatisfactory/Satisfactory
6	Other (e.g. share of domestic participation, international experience, etc.)	Unsatisfactory/Satisfactory

Section 3 Determining Whether a Bidder is “Satisfactory”

In order to achieve an overall “Satisfactory” rating the Bidder should achieve a “Satisfactory” on each of the five categories set out in the Section 2 of this Appendix. A “Satisfactory” rating does not meat that the Bidder should receive a “Satisfactory” on each of the individual questions mentioned on the Chart under Section 4 of this Appendix, it means that the Bidder has met the basic level of competency in each of the five categories of evaluation.

Section 4 Submission Requirements and Evaluation Criteria

Demonstration of capacity to prepare successful construction license application

Proposal submission section	**Content of the Section**	**Evaluation Criteria**
Section 1 Demonstration of capacity to prepare successful construction license application	• Demonstration of a licensing history 1. Past planned versus realized licensing schedules with explanation of discrepancies 2. Major issues raised during licensing and how they were addressed 3. Any licensing preconditions or pre-licensing outcomes 4. Experience (if any) with the regulator • Demonstration of a credible plan, with sufficient resources to support an "on schedule" construction license application 1. Set out a deployment plan addressing all risks and strategy for mitigation 2. Set out an activity based timeline 3. Set out all discrete work packages 4. Set out current path and key milestones 5. Set out current status and progress to date • Listing of existing or anticipated licensing issues and approaches to resolve them 1. Description of required resources, type, relevant experience and qualifications 2. Evidence of resource availability • Description of the project team	• Amount and level of success of past licensing experience and its adaptability to the current project 1. Number of licenses 2. Past performance against licensing schedules 3. Level of success in receiving licensing approvals 4. Applicability of past licensing interactions to the current project • Project timeline for obtaining a construction license 1. Level of detail 2. Demonstrated knowledge of licensing and permitting procedures 3. Progress to date • Credibility of plan 1. In-depth knowledge 2. Feasibility of approach 3. Level of qualified resources 4. Demonstrated ability to foresee and

		mitigate licensing risks • Qualifications and credibility
Section 2 Demonstration of a plan to address safety and security issues	• Plan with detailed schedule of work required to prepared a reliable safety case 1. Activity based time line for safety case preparation and submission 2. Identification of all discrete work packages 3. Identification of current work plan and key milestones of safety case preparation 4. Description of risk identification • Description of approach to demonstrate compliance with safety requirements • List of documentation • Required project resources • Description of project monitoring and risk management for safety case preparation	• Completeness of safety case 1. Level of detail 2. Demonstrated knowledge of safety requirements 3. Progress to date on preparation of safety case • Credibility of submitted plan and other documentation • Level of detail of relevant information • Demonstrated ability to foresee and mitigate licensing risks
Section 3 Willingness and capability to deliver the project	• Confirm that the respondent either itself or through the consortium willing to provide all required element of the project • Description, structure and organizational chart of the team • Subcontracting relationships and contractual arrangements • Realized versus planned schedule and budget	• Level of applicable experience and level of responsibility on the past projects • Experience in delivering successful projects • Level of success in developing and maintaining subcontractor relationships • Degree of success in delivering past project in time and on budget
Section 4 Financial strength	• Financial information supporting strong position of the respondent 1. Audited annual financial statements and the latest 2. Companies credit rating from an independent source 3. Details of the Respondent's approach to secure the performance obligations	• Evidences of strong financial position, including credit ratings and balance sheet

Section 5 Legal position	Detailed description of any adverse ruling against the Respondent or any litigation 1. Details of any insolvency, bankruptcy or similar applications by or against the Respondent 2. Disqualification in a procurement process related to the project or similar to it 3. Detailed description of any conviction (administrative regulatory, penalty, sanction implementation or)investigation for violation of regulations related to use of nuclear energy or safety norms 4. Any anticipated claims, proceedings, prosecutions or obligations	

D. Appendix 3 – Proposal Submission Forms

To: (address)

Attentions: (contact person)

Respondent: ___________________

Date: __________________________

Respondents' Offer

In consideration of (........................) and in accordance with the RFP, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged we hereby agree as follows:

1. Definitions

Unless otherwise defined in the Proposal Submission Form the terms and expressions used in the Form have the meanings given in the RFP.

2. Representation and Warranties

The Respondent represents and warrants as follows:

A. We and to the best of our knowledge, our Advisers, employees and representatives:

   a) have prepared and submitted the proposal Submission Form independently and without connection, knowledge, comparison of information or arrangement, direct or indirect, with any other respondent; and,

   b) have not contravened communication restrictions provided by the RFP;

B. We have not engage in any form of political or other lobbing, directly or indirectly, by influence the outcome of this RFP process or contravened lobbing or contract prohibition provisions of the RFP .;

C. We have not contravened RFP provisions on convening general or commercial confidential meetings, as well as provision on confidentiality agreements;

D. At the time of submitting of the Form (name of the company) is in full compliance with all tax statutes and any financial obligations;

E. (Name of the company) is based on and relies solely upon our own knowledge, information , judgment and investigation

3. RFP Terms and Conditions Binding

A. By submitting this offer the Respondent agrees to be bound by and to comply with the terms and conditions of the RFP documents as of the Proposal Submission Deadline and acknowledges and agrees that if the Respondent submits the Proposal Submission Form without material deviation in accordance with the RFP Documents requirements, a “Bidding Contract” is created between (name of the company) and (the Client). The terms and conditions of the Contract are set out in the RFP.

B. The Respondent acknowledges and agrees that the Proposal Submission constitutes the an offer that is irrevocable in accordance with the terms and conditions of the RFP Documents.

C. The Respondent confirms that the Proposal Submission is based on the terms and conditions of the RFP Documents as of the Proposal Submission Deadline.

D. The Respondent acknowledges and agrees that the Proposal Submission Form is irrevocable until the expiration of the Proposal Validity Period.

E. The Respondent confirms that it has examined the RFP Documents in detail and confirms that it has received all pages of all documents consulting the RFP Documents as of the Proposal Submission Deadline.

F. The Respondent confirms that it made all necessary inquires with respect to Appendixes and Amendments to the RFP Documents that were issued prior to the Proposal Submission Deadline.

In witness whereof the Respondent has executed this Proposal Submission Form as of the date first above written.

[name of the Respondent]

Per: ___________________________

(name, title)

Per: ___________________________

(name, title)

E. Appendix 4 – Financial Submission Form

F. Appendix 5 - Contract (including all related Schedules, Appendixes and Attachments) as listed in the BIS Data Sheet

Initial Planning Studies

Appendices

October 2008

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APPENDIX TO CHAPTER 1: RESPONSES TO NUCLEAR PLANT VENDOR SURVEY QUESTIONNAIRE

Survey Response from Atomic Energy of Canada Limited

1. Discussion of any export limitations, or restrictions on providing detailed component design information, analysis details, and computational programs and source codes

Canadian Nuclear Safety Commission (CNSC) controls the import and export of nuclear materials and other prescribed substances, equipment and technology. Canada has undertaken nuclear cooperation only with those states that have signed a Nuclear Cooperation Agreement (NCA) with Canada. The NCA contains several assurances including:

- A non-explosive use commitment;
- A provision for fall-back safeguards;
- Retransfer, enrichment and reprocessing controls; and,
- Assurance of adequate physical protection measures.

Since 1976 Canada has engaged in nuclear cooperation only with states that have ratified the Treaty on the Non-Proliferation of Nuclear Weapons (NPT) or have taken an equivalent binding step and accepted International Atomic Energy Agency (IAEA) safeguards on the full scope of their nuclear activities.

2. Seismic design criteria

The CANDU 6 structures have a robust design for seismic events. Based on our experience, the CANDU 6 structures can withstand a DBE (SSE in the US) with a horizontal peak ground acceleration of 0.3 g and slightly higher without expensive design changes to the structure. The DBE for the Akkuyu (Turkey) site has a peak ground acceleration of 0.25g and hence the equipment and the structures do not require any major modifications for this level.

However, the problem is that the equipment will have difficulty in qualifying, withstanding the earthquake and operating during and after the event, for DBE of higher than 0.3g. In particular, the Fuelling Machines will have difficulty in qualification above 0.3g. For a site such as ANPP, with DBE between 0.35g to 0.5g, AECL's preferred option would be to place the critical Reactor Building on seismic isolators which would isolate the building significantly from a seismic event. This would result in the qualification of the equipment and the structure for 0.5g without major structural changes above the base slab of the Reactor Building. The cost of the isolators is not known but may be in the range of $100 m.

3. Load following capability

Considerable data is available documenting deep load changes (down to 60% and back to 100%) in the Bruce B and Embalse stations provides substantial data to confirm the load following capabilities of CANDU reactors. The plant power-maneuvering rate is limited by the turbine design, and is typically 5 to 10 percent of full power per minute. During normal plant operation, the reactor power may reduce to 60 percent of full power at rates up to 10 percent of full power per minute. The power may be held at the new lower level, indefinitely. Return to full power can be accomplished within three hours,

4. Interface requirements with the electric grid including power interconnect diversity, requirement for redundant supplies and transient limitations.

No response

5. Black start capability and tolerance for total loss of off-site power

The unit is capable of reaching 100 percent net electrical output from a cold shutdown within 12 hours. In the event of a temporary or extended loss of line(s) to the grid, the unit can continue to run and supply its own power requirements. The turbine steam bypass to the condenser is capable of accepting the steam flow during loss of line or turbine trip. Following a shutdown from sustained full power operation, the reactor can be restarted within 22 minutes (the poison override time) and returned to full power operation. Otherwise, a 'poison-out' period of about 36 hours results, after which the reactor can be restarted.

6. Capital investment costs

Overnight Capital (2 unit turnkey plant) is $2,317 per kWe net including all owner costs

7. Nuclear fuel cycle costs

Fuel cost:

Front End $2.73 / MWh

Back End $1.64 / MWh

8. Operation and maintenance (O&M) costs and estimated professional, technician, and crafts staffing requirements for operation and maintenance

Annual O&M for 2 unit = Labor cost of 843 Staff plus $68.14 M

The O&M cost includes provisions for:

- plant maintenance costs (materials, labor and heavy water makeup)
- support costs (head office, external services)
- outage costs (labor, material and services)
- on-going capital improvements as expense
- other (taxes, insurance and other fees)

9. Scope, schedule, and estimated cost of major life cycle refurbishment tasks

The design life for current CANDU 6 plants is 40 years. However, recent review of the operating CANDU 6 plants, indicate that an operating life in excess of 60 years is probable. The 60-year operating life can be achieved in a single plant shutdown at around mid-life for a duration of 12 months or less to perform mid-life modernization and refurbishing, to include the replacement of the pressure tubes and the steam generators. Pressure tube replacement cost estimate is about $300 M for EC6

10. Estimate of owner's construction cost elements not included in supplier scope

The owner's cost is the cost outside the vendor's scope of supply:

- ·project approvals, permits, licenses,
- ·owner's project team (contract, administration, etc),
- ·site preparation, including site services and access roads,
- infrastructure and construction indirects (water, electricity during construction),
- owner's facilities - switchyard (main station connection and grid
- connection), guard house, administration building (includes capital equipment (simulator)),
- ·training of owner's staff and their participation in commissioning, and security.

11. Decommissioning cost

$790 M for 2 units.

12. Construction time and overall project schedule

Current CANDU 6 projects use a 70-month project schedule (contract effective to in-service) and a 54-month construction schedule. The Quinshan Phase III, Unit 1 and 2 project has successfully achieved milestones consistent with this.

13. Construction staffing levels, including identification of critical craft requirements, and identification of critical on site component assembly operations (such as major pressure vessel assembly

For 2 unit Quinshan the construction workforce was 1000 local workers with 46 foreign supervisors.

14. Projected unit availability and refueling intervals

Online refueling. Plant Availability Factor:90% Outage for Maintenance 25 days once every 2 years per unit

15. Dimensions and weight of major components in "as shipped" configuration

See attached table. Largest component is Calandria @ 9 meters, 250 ton. Heaviest is Moisture Separator Reheater @ 350 ton

16. Programs for domestic participation and technology transfer

No response

17. Fuel strategy, scope of supply and services

CANDU fuel cycle options of current interest include: Natural uranium (NU), Slightly

Enriched Uranium (SEU), Recovered Uranium (0.9%U235) (RU), Direct Use of spent

LWR fuel In CANDU (DUPIC), the Thorium/U233 Cycles and the Transuranic mix.

18. Training of owner's staff for construction, commissioning, operation and maintenance, and support for on-site training facilities

For Quinshan, operating staff of 232 was trained in Canada

19. Critical spares, wear parts, and consumables

No response

20. Terms of service contracts

No response

21. Status of design certification or licensing in the country of origin and other countries

CANDU 6 meets the requirements of the Canadian Nuclear Safety Commission (CNSC). There are two operating CANDU 6 plants in Canada (Point Lepreau and Gentilly-2). CANDU 6 units have also been successfully licensed in Argentina, Romania, South Korea, and China. It also complies with IAEA design guides.

22. Construction and operating experience of existing plants, including support for owners groups and formal operating experience feedback programs

With eleven CANDU 6 units in operation and over 100 cumulative years of operation, CANDU 6 is a modern and proven design available for immediate construction. CANDU owners group very active in sharing OE and developing common solutions.

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

23. Identification of long lead time components

Few if any. CANDU 6 design is well known and supply chain is already established

24. Estimated time from contract award to startup

EC6 has a 69 months project schedule from contract effective date to in-service for the 1st unit. The 2nd unit will take an extra 9 months to complete

25. Estimate of construction payment schedule

. The indicative disbursement schedules for a 2 unit EC6 project are:

Months	**0**	**1-6**	**7-18**	**19-30**	**31-42**	**43-54**	**55-56**	**57-78-**
Percent of total cost	**8.00%**	**9.4%**	**24.1%**	**23.4%**	**15%**	**9.8%**	**5.6%**	**4.7%**

26. Estimated quantities of low and intermediate radioactive waste, including waste from major refurbishment tasks

The average annual volume of contaminated liquid wastes are approximately 18,000 m3 per year. Contaminated or potentially contaminated liquids are collected in the liquid waste collection tanks.

Annual Estimated Solid Radioactive Waste

Spent Resin 7 m3

Low level combustible wastes 22 m3

Low level non-combustible waste 9 m3

Filters 2 m3

Other wastes 1 m3

Total 41 m3

27. New fuel storage capacity and capability for additional storage to insure against supply disruption

Not limited

28. Identity of all fuel suppliers with experience supplying this NPP fuel

Country	**City**	**Company**
China	Baotou	CNNC
Pakistan	Chashma	PAEC
Argentina	Ezeiza	CNEA
India	Hyderabad	NFC
Canada	Peterborough	GE Canada
Romania	Pitesti	SNN
Canada	Port Hope	ZPI
Canada	Toronto	GE Canada
Korea, Rep. of	Yuseong	KNFC

29. Any nationally imposed restrictions on fuel ownership, retention, reprocessing, etc.

Canada does not accept return of spent fuel

30. Extent of support for public information and outreach programs

No response

31. Capability for plant operation at a range of final heat sink conditions (e.g.: dry cooling), impact on plant parameters and safety studies, and ability/willingness to incorporate dry cooling in the design

Can use dry cooling with efficiency penalty

Other

Current CANDU 6 spent fuel bay capacity with the most up-to-date storage rack design can store up to 10 years of spent fuel. The dry spent fuel storage system is an air-cooled concrete module that houses a number of metal canisters containing spent fuel. This arrangement provides highly efficient heat rejection, excellent shielding and complete structural soundness. Dry spent fuel storage can be applied as soon as after 6 years pool storage, and is licensed locally.

Quinshan is a 2 unit CANDU 6 plant that was built by a team of AECL, Bechtel, Hitachi, and Chinese partner. AECL was the lead for this fixed price EPC contract. Plant was constructed ahead of schedule and under budget. A major reason for success of the construction project was that CANDU 6 design is well known and supply chain is already established.

Summary of Largest Components Requiring Shipment to an EC6 Construction Site

Item No.	Name of Equipment	Qty	Gross Weight (metric tons)	Overall Dims (m)	Comments
1	Personnel Airlock	1	30.0	4.67 x 3.96 x 3.15	
2	Equipment Airlock	1	110.0	7.5 dia. X 12.5 L	
3	Stainless Steel Liner for Fuel Transfer Structure		37.5	Part A 4.89 x 3.35 x 9.1 Part B 7.62 x 2.44 x 9.7	Constructed in 2 parts (A & B) Probably constructed at site. Transportation within site boundary only
4	Degasser Condenser	1	49.0	2.23 Dia. X 7.52 L	
5	Feeder Header Frame	2	55.0	7.29 x 6.61 x 2.92	
6	SB 100 ton Crane	1	27.0 largest piece	3.4 W. x 2.2 H. 13.85 L Largest crate.	Shipped in 6 crates
7	Moderator Heat Exchanger	2	56.0	1.93 Dia. x 10.37 L	
8	RB Boiler Room Crane	1	20.0 largest piece	6 x 21 L. Largest crate	Shipped in 5 crates
9	ECC Tank	3	104.0	4.2 Dia. x 12.7 L	
10	Pressurizer	1	110.0	2.13 Dia. x 16.15 L	
11	Steam Generator	4	200.0	4.3 (2.9) Dia. x 20 L.	
12	Calandria	1	250.0	8.53 W. x 8.96 H. 8.48 L.	
13	PHT Pump Motor	4	46.0	4.2 x 4.11 x 4.37 H	
14	TB trusses or main crane beam	2		47 L	Longest component. Transportation probably within the site boundary only
15	Standby Diesel Generators	2	150.0	7 x 5 x 5 H	
16	Turbine Generator Rotor	1	150.0	15 x 4 x 4 H	

17	Turbine Generator Stator	1	320.0	12 x 6 x 6 H	
18	Moisture Separator Reheater	2	350.0	25 x 5 x 5	
19	Deaerator Storage Tank	1	85.0	15 x 5 x 5	
20	Main Output Transformer	3	150.0	8 x 5 x 8	3 single phase transformers. Could possibly be one transformer @ 450.0 t
21	Condenser Modules	2 or 3	200.0	15 x 5 x 5	
22	Main Feed Water Pumps	3	50.0		
23	Condensate Storage Tank	1		4 x 4 x 28	

Note: Items such as S/G's, Calandria, Pressurizer, Degasser Condenser do not have packaging as such except for shrink wrap protection and support cradles.

Survey Response from Westinghouse

1. Discussion of any export limitations, or restrictions on providing detailed component design information, analysis details, and computational programs and source codes

Armenia & USA would need to execute a nuclear technology export agreement under provisions of Atomic Energy Act. Technology export would also need to be approved under the guidelines of the Nuclear Suppliers Group.

2. Seismic design criteria

AP1000 design is based on 0.3 g acceleration for the Safe Shutdown Earthquake (SSE). Because of the broad response spectra, there is some conservatism, and analyses of a particular site's conditions may justify a higher value. They have investigated use of seismic isolators at a site in Japan to achieve a 0.8 g SSE. Adding seismic isolators would add well over $100m to the cost.

3. Load following capability

AP1000 can accept an instantaneous 10% power drop. Can ramp from 100% to 50% over two hour period.

4. Interface requirements with the electric grid including power interconnect diversity, requirement for redundant supplies and transient limitations.

Because AP1000 does not rely on AC power for safety, it does not have any special grid interface requirements. The design uses a Toshiba turbine generator which is particularly robust to changes in voltage and frequency.

5. Black start capability and tolerance for total loss of off-site power.

AP1000 can accept a loss of offsite power (LOSP) without trip, using steam dumps. However, to have black start capability, a gas turbine would need to be added to the design.

6. Capital investment costs

The current estimate for the supplier scope in the US is $3,500 per kw capacity for a 2 unit plant. This is very much dependence on local market conditions for labor and commodities. For example in the US, management and supervision cost is 20% of total labor cost. In some foreign locations, it is 50% of labor cost because local labor cost is lower but the cost of sending supervisors to the country is much higher. Transportation costs must also be considered. Cost could be $4,000/kw.

7. Nuclear fuel cycle costs

Fuel costs are estimated at $7-$10 per MWh at current uranium prices of $100/pound. The fuel is up to 5% enriched and produces about 62 GWdays/ton of uranium.

8. Operation and maintenance (O&M) costs and estimated professional, technician, and crafts staffing requirements for operation and maintenance

O&M staff for 2 units in US is estimated as 800-900 people. For single unit it would be about 600 people. O&M cost is primarily staff wages and is estimated as $80-90m/year in US.

9. Scope, schedule, and estimated cost of major life cycle refurbishment tasks

May require turbine generator overhaul. Steam Generators are designed for replacement but are designed to last 60 years.

10. Estimate of owner's construction cost elements not included in supplier scope.

The major cost is wages for operating staff during construction for training. Owner's cost estimated as 10-15% on top of supplier's total overnight construction cost.

11. Decommissioning cost

Decommissioning estimate is $500m in current year dollars.

12. Construction time and overall project schedule

Estimate 6 years from contract signing to commercial operation. This assumes that:

- The site permits and licensing are in place
- The long lead components are ordered at least 2 years before contract signing

13. Construction staffing levels, including identification of critical craft requirements, and identification of critical on site component assembly operations (such as major pressure vessel assembly

Construction workforce estimated at 1,500 – 2000 people. Critical skills are welders, heavy lift crane operators, nondestructive test/inspection technicians, and construction management

14. Projected unit availability and refueling intervals

Estimated average unit availability over 20 years is 93.4%, including refueling and a major outage for turbine generator refurbishment. Equivalent forced outage rate is estimated to be no more than 1.5%. Refueling is 17 days every 18 months.

15. Dimensions and weight of major components in "as shipped" configuration

The largest component is the steam generator (SG) at 650 tons. Other large components are the reactor pressure vessel (RPV), transformers, generator stator, and large tanks. It is not feasible to assemble the RPV and SG on site. However, construction modules may be assembled locally. Transport by large trailers is feasible but often requires road reinforcement and widening and bridge reinforcement.

16. Programs for domestic participation and technology transfer

Westinghouse will buy from any local sources available. One area of local participation is assembly of construction modules, worth about $200 M. The license to the technology is available but very expensive.

17. Fuel strategy, scope of supply and services

Typically Westinghouse manufactures fuel using enriched Uranium provided by the customer. However, they could buy the uranium and provide complete fuel service. US regulations prohibit them from accepting the return of spent fuel.

18. Training of owner's staff for construction, commissioning, operation and maintenance, and support for on-site training facilities

Westinghouse provides full training for operations and maintenance and will oversee the NPP startup.

19. Critical spares, wear parts, and consumables

Westinghouse can provide critical spares and consumables for additional price ($200-300 M). Spares include reactor coolant pump, turbine & generator rotors). Westinghouse recommends sharing spares inventory with other plants, one of the advantages of the standard plant design.

20. Terms of service contracts

Westinghouse offers full service contracts at competitive prices. Westinghouse also provides the owner with all technical information needed to operate, maintain, and modify the plant. However, technical information is proprietary and not transferable to other service providers.

21. Status of design certification or licensing in the country of origin and other countries

AP1000 has a design certification from the US NRC. A revision to the design certification to address issues that have come up in the US licensing process is under review and should be approved by 2010. In China, construction permit should be approved by 2009, operating license by 2013. In UK design certification review is in progress, expected by

2010. AP1000 has a certificate of compliance with the European Utility Requirements Document.

22. Construction and operating experience of existing plants, including support for owners groups and formal operating experience feedback programs

Operating experience factored into design. Many of the major components are from existing PWR design (e.g., SG is from system 80+, fuel is from earlier Westinghouse design). Owner participation in AP1000 and PWR owner's groups is encouraged.

23. Identification of long lead time components

There are 25 long lead items include RPV, SG, reactor coolant pump, containment liner. These items cost about $100 M and must be ordered at least 2 years before the beginning of the construction period.

24. Estimated time from contract award to startup

AP1000 estimates a 6 year construction schedule based on modular construction. However, long lead items must be ordered 2 years before the start of this schedule. US utilities are ordering now or a plant they would like to startup in 2016 (8 years)

25. Estimate of construction payment schedule

Estimate 1/3 of total cost spent by the time that concrete pour begins.

26. Estimated quantities of low and intermediate radioactive waste, including waste from major refurbishment tasks

AP1000 produces 5,800 cubic feet of LLW per year (uncompacted). Because the reactor control uses mechanical rod movement rather than changing Boron concentration, the amount of liquid radwaste is much less than previous design PWRs. The LLW waste estimate does not include replaced steam generators.

27. New fuel storage capacity and capability for additional storage to insure against supply disruption

Reload requires 65-72 assemblies. Design includes new fuel storage for 72 assemblies. However, new fuel could also be stored in spent fuel pool. Spent fuel pool holds 18 years worth of fuel (950 assemblies).

28. Identity of all fuel suppliers with experience supplying this NPP fuel

Fuel for Westinghouse NPPs is sold by Westinghouse, AREVA and maybe Russia in the future. Other manufacturers are in Korea, Japan, Spain, China,

29. Any nationally imposed restrictions on fuel ownership, retention, reprocessing, etc.

US regulations do not allow return of spent fuel. See question 1 on US 123 agreement

30. Extent of support for public information and outreach programs

Westinghouse would provide support to public outreach but did not participate in EIA in China.

31. Capability for plant operation at a range of final heat sink conditions (e.g.: dry cooling), impact on plant parameters and safety studies, and ability/willingness to incorporate dry cooling in the design.

The standard design uses natural draft wet cooling tower. There is no safety reason why dry or hybrid cooling could not be used, but it would cost more and have lower electrical output/efficiency.

Other notes:

Plant could be built as a Build Own Operate (BOO) project, hiring a nuclear utility company to operate the plant. The O&M cost would be 2-3 times higher.

Westinghouse is considering a project in South Africa, 70 KM from nearest port. There are shortages of skilled labor, no housing for foreign labor, inadequate roads. Housing may cost as much as $1B. Road improvements will cost hundreds of million. Road transport will require several weeks for each of heavy component.

The turbine generator for the standard design is manufactured by Toshiba. However, the AP1000 in China will use the MHI design, for which they have a license to manufacture locally.

Modular construction: Modules can be built on site; however, this requires extensive lay down areas and heavy load paths. Several cranes with 1,500 ton capacity are needed.

In a meeting with NEI, it was suggested that there was limited risk in ordering AP1000 long lead components because they could be resold to other owners if the project is not built.

Japan Steel and Dousan are the only current suppliers of Forgings for RPV. However, other suppliers (e.g., Ansaldo, MHI, BWI Canada, IHI) are developing capability. Other supply chain constraints are SG Tubes, stainless steel components and Reactor coolant pumps.

Survey Response from ATOMSTROYEXPORT

Main characteristics of nuclear power unit AES-92

Technical characteristics

Capacity (thermal), MW – 3000

Capacity (electrical), MW – 1068

Life time, years – 60

Possibility to construct on every type of grounds without changing the lay-out and building design

Estimated frequency of core heavy damages during the accidents, 5.6 10-8 per year

Plant efficiency coefficient (estimated), % (brutto) - 35.6

Load factor, % - 0.92

Electric energy production, mlrd kWh - 7.5 – 8.0

Safety Systems

- Safety systems building structure - 4 X100%
- Passive and active systems availability
- "Defense in depth" protection
- External impact protection: airplane, tsunami, earthquake, flooding
- Melted fuel trap (core catcher)

Economic characteristics

Construction specific cost - 1500 – 1800 $/kW

Construction time, months - 54

Net Cost - 2.3 USA cent/kWh

General parameters of WWER-1000 types V-466, V-428 and V-412.

Characteristics	Reactor type		
	V-466	V-428	V-412
Reactor plant			
Rated thermal power of reactor, MWth	3000	3012	3012
Electric capacity of NPP (gross), MWe	1046	1060	1000
Number of loops	4	4	4
Reactor lifetime, years	60	40	30
Annual hours of operation at rated power (effective), hours	7800	7000	7000
Reactor			
Coolant absolute pressure on exit from core at rated power, MPa	15.7	15.7	15.74
Rated coolant flow rate through reactor, m3/hour	86000	86400	86000
Coolant temperature on outlet from reactor, ^{0}C, rated	321	321	321
Coolant temperature on inlet into reactor, ^{0}C, rated	291	291	291
Reactor temperature range, ^{0}C, rated	30	30	30
Reactor pressure vessel			
Diameter of cylindrical part of pressure vessel near core, mm	4150	4150	4150
Thickness of wall, mm	192,5	192,5	192,5
Thickness of anti-corrosion facing, mm	9	8	8
Length, mm	10897	11185	11185
Material	15X2HMFA	15X2HMFA	15X2HMFA
Number of assemblies in the core	163	163	163
Equivalent diameter of core, mm	3160	3160	3160
Height of the core in cool condition, mm	3530	3530	3530

Number of fuel elements in an assembly	311	311	311
Maximum linear thermal flow (capacity) of fuel element, W/cm	448	448	448
Maximum enrichment of fuel with U235 isotope, %	4,4	up to 4,4	up to 4,4
Fuel burnup in an assembly (in steady-state conditions), MWday/kgU	47	43	43
Steam generator			
Internal diameter, mm	4000	4000	4000
Height (length), mm	13840	13840	13840
Type	horizontal	horizontal	horizontal
Number of tubes	10978	10978	10978
Heat exchange surface, m^2	6038	6038	6038
Layout	corridor	staggered	staggered
Rated steam output, tons/hour	1470	1470	1470
Rated pressure, MPa	6,27	6,27	6,27
Diameter and thickness of heat exchange tubes, mm	16x1,5	16x1,5	16x1,5
Material of tubes	08X18H10T	08X18H10T	08X18H10T
Reactor cooling pump			
Type	GCNA-1391	GCNA-1391	GCNA-1391
Displacement, m^3/hour	22000	22000	22000
Head, MPa	0.588	0.588	0.588
Power rating, kW	6800	6800	6800
Power rating (hot water), kW, no more than	5100	5100	5100
Reactor main loop			
Internal diameter of hot (cold) pipeline, mm	850	850	850
Thickness of pipeline, mm	70	70	70

Pressurizer			
Pressure, MPa	15,7	15,6	15,6
Volume, (total) m^3	79	79	79
Volume of water during power operation, m^3	55	55	55
Power rating of heaters (total), kW	2520	2520	2520
Reactor Emergency Cooling System Containers			
Rated pressure, MPa	5,9	5,9	5,9
Volume, m^3	60	60	60

APPENDIX TO CHAPTER 3: DEMAND FORECAST REVISION

Introduction and Background

The value and the shape of the potential total demand within the planning horizon have key importance for ability of Armenian Power System to accommodate a new Nuclear Plant. The total demand consists of two major components. These components are the electricity gross domestic demand[1] and electricity export/import values.

Previous studies and analyses performed by different State Institutions and consultants indicated potential possibility for commissioning and running a new Nuclear Unit within the system without affecting its' security and reliability.

The main purpose of this revision is to evaluate the recent Demand Forecasts based on the actual data collected during the last two years and to analyze if the current peak and demand values and growth rates are consistent with the previously forecasted. Another major change since the latest generation planning performed for Armenia is related to the new actual and potential exporting capabilities of Armenian transmission system and official export forecasts.

The most recent comprehensive demand forecast for Armenian power sector was performed within the Armenian Power Sector 2006 Least Cost Generation Plan (LCGP 2006).

The Least Cost Generation Plan 2006 is an updated version of the extensive efforts made to produce the previous Least Cost Generation Plans. This plan was prepared by the Ministry of Energy of the Republic of Armenia (RoA) with support from PA Consulting Group (USAID's "Program to Strengthen Reform and Enhance Energy Security in Armenia").

A scenario based approach was used to forecast the electricity demand for the development of the 2005 and 2006 LCGPs. This methodology was used to take into account the new environment in Armenia's electric power sector. In October 2002, the Distribution Company was privatized. This event increased the level of complexity for modeling, because upon privatization the company unveiled a new campaign aimed at reducing commercial losses. The results were positive and the overall situation in the sector was improved. But, it added new complicating factors to forecasting. Due to lack of data, it was impossible to differentiate if the changes in electrical demand were caused by improved economy of the country, improved management practices of the Distribution Company, or a reduction in commercial losses.

[1] Including ancillary consumption and electricity losses

Three scenarios (High, Base Case, and Low) were considered for the 2005 LCGP, which differ by the rate of growth in energy consumption and associated system peak load.

High Growth Scenario is characterized by higher development of industries, due to which annual load factor rises from current 50.0% to 55.1%.

In the **Reference Case** it is assumed that the main driving factors would be the growth in residential and commercial consumption, while industrial sector would also increase consumption, but not as substantially as the High Growth Scenario. For this reason, the average annual load factor would also increase, but at a lower rate than the High Growth Scenario. Hence, the average annual load factor would reach 52.8%.

The **Low Growth scenario** is based on the presumption that no substantial changes would occur in the structure of electric power consumption, and the load factor would remain at the same level as it is now – around 50.0%.

The High Growth Scenario projects a 4% growth in generation and 3.4% in peak load. The Reference Growth Scenario forecast a 3.1% growth in generation and 2.7% in peak load, while the Low Growth Scenario assumes that the generation and peak load will increase by 1.9% per annum.

The summary of Demand forecasts performed within the scope of LCGP 2005 and 2006 is presented in a Table 1 below.

Table 1. Summary of Demand Scenarios (2005-2025) Analyzed in LCGP

	Base Year 2005	Low Growth Scenario 2025	Reference Growth Scenario 2025	High Growth Scenario 2025
Total Domestic Consumption (GWh)	4,150	6,540	8,048	9,862
Gross Generation for Domestic Needs (GWh)	5,629	8,306	10,170	12,398
Gross Peak Demand (MW)	1,293	1,902	2,198	2,569
Average Annual Load Factor (%)	49.7%	49.9%	52.8%	55.1%
Average Annual Growth Rate of Consumption	N/A	2.4%	3.4%	4.4%
Average Annual Growth Rate of Generation	N/A	2.0%	3.0%	4.0%
Average Annual Growth Rate of Peak Demand (%)	N/A	1.9%	2.6%	3.4%

2006 - 2007 Data and Analysis

Actual Data Records from various reports and sources including Public Service Regulatory Commission (PSRC), Settlement Center CJSC and Electric Power System Operator (EPSO) was summarized and computed in order to evaluate the accuracy and consistency of the Demand Forecasts performed within the scopes of 2005 and 2006 Least Cost Generation Plans.

Although the data records from these sources sometimes do not match each other, the differences and variations are not very significant[2].

Hence, for the purpose of this study the data from PSRC's published annual reports was used as the supposed to be the final and most accurate[3].

The summary of data from PSRC published reports and basic computations are presented in a Table 2 below.

Table 2. Summary of PSRC data for 2006-2007 and basic computations

PSRC REPORTS*	2005	2006	2007	Growth Rate
GROSS GENERATION	6316.1	5940.9	5897.5	-3.4%
IMPORT	337.6	355	418.7	11.4%
EXPORT (Georgia +Iran)	1045.2	608.2	313.3	-45.3%
Gross Domestic Consumption (Computed)	5608.5	5687.7	6002.9	3.5%

As it can be noted from the Table 2 above although the generation and export values were decreasing during the last two years, the Gross Domestic Consumption (GDC) is characterized by a steady growth. The average growth rate for GDC is around 3.5% which is close to the Average Annual Growth Rate of Consumption forecasted in previous studies.

Further analysis of the data and operating with the Net Domestic Demand (NDD) allowed making additional conclusions. The summary from PSRC published reports, EPSO data records and basic computations are presented in a Table 3 below.

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[2] For example: The data available from EPSO records neither includes some of the small hydro power plants nor the newly commissioned Combined Cycle at the Medical University.

[3] Source: http://www.psrc.am/am/?nid=297

Table 3. Summary of PSRC reports and EPSO records for 2006-2007 with basic computations

PSRC and EPSO DATA	2005	2006	2007	Average Growth Rates
Net Domestic Demand (PSRC)	4179	4309	4621	5.2%
Gross Generation (PSRC)	6316.1	5940.9	5897.5	-3.4%
GROSS Peak Loads (EPSO)	1293	1284	1242.8	-2.0%
Annual Net Demand Growth Rate (Computed)	N/A	3.11%	7.24%	
Annual GROSS Peak Growth Rate (Computed)	N/A	-0.70%	-3.21%	
Load Factor (Computed)	55.8%	52.8%	54.2%	

As it can be noted from the Table 3 above the Average Growth Rate for NDD is about 5.2% which is higher than 4.4% forecasted in High Scenario of 2005 and 2006 LCGP as well as exceeds the 3.5% of GDC growth rate.

The difference between growth rates for GDC and NDD can be explained by the positive results of Private Distribution Company's campaign against the commercial losses. A portion of commercial losses was reduced and now is being counted within the value of effective sales. It does not affect previous and existing GDC value since the same or close amount of electricity was already included in GDC calculations as electricity physically consumed in Armenia. In other words there is a transfer of physically consumed electricity between the categories. The data about the losses and reduction rate is provided in a Table 4 below.

Table 4. Technical and Commercial Losses according to PSRC published annual reports

PSRC REPORTS	2005	2006	2007	Reduction Rate
Technical losses in Distribution Network	10.4%	9.9%	9.5%	-4.4%
Commercial losses in Distribution Network	5.9%	5.2%	4.9%	-8.9%

Previous High Growth Scenario is characterized by higher development of industries, due to which annual load factor rises from 50.0% to 55.1%. Average Load Factor computed on the bases of data for 2006 and 2007, which is above the 54%, indicates certain increase in industrial consumption. This can be also noted from the categorized consumption published in reports (Table 5).

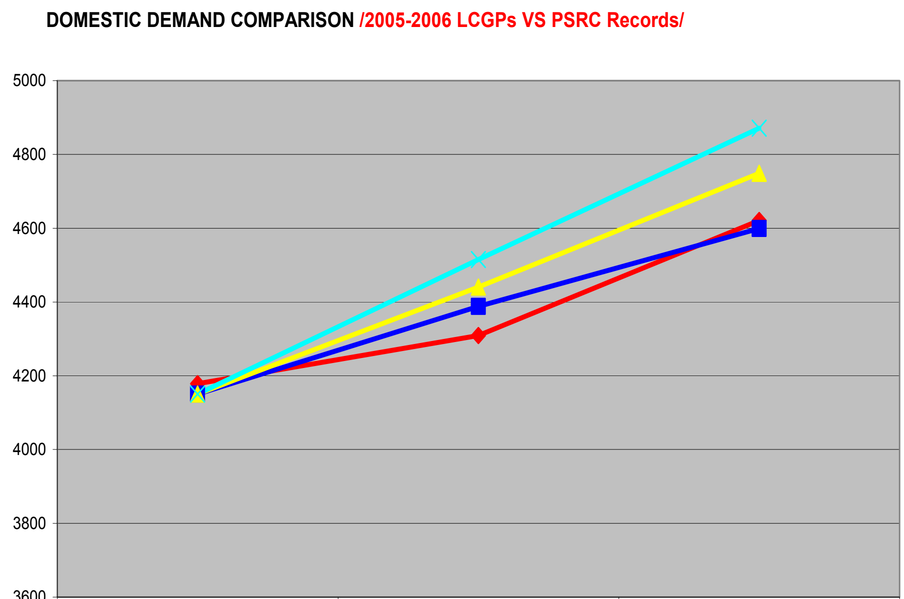
Table 5. Consumption by categories

PSRC REPORTS	2005	2006	2007	Growth Rate
Residential	1498.1	1530.9	1585.3	**2.9%**
Budget Organizations	197.4	203.1	218.8	**5.3%**
Industry	1019.8	1039.1	1209.8	**8.9%**
Transport	113.2	115.1	123	**4.2%**
Irrigation	228.6	226.8	180.5	**-11.1%**
Drinking Water and Sanitary	192.8	177.6	182.1	**-2.8%**
Other Consumers	929.6	1016.4	1122	**9.9%**

Stated above increase of electricity consumption by industrial consumers could eventually improve the annual and daily demand shapes which were recognized as one of the critical issues for new nuclear unit commissioning.

Comparison of actual and forecasted annual demand values and growth rates for each year would not be really representative due to possible demand fluctuations specified by weather and/or other conditions. It can be noted from the comparison Chart 1. Hence, although simplistic because of the shortness of the observation period (2-3 years), trends and average growth rates provide much better understanding of demand dynamics.

Chart 1



	2005	2006	2007
Domestic Demand (PSRC)	4179	4309	4621
Low Growth Scenario	4150	4388	4599
Reference Scenario	4150	4441	4749
High Scenario	4150	4515	4871

Forecasted Increase of Electricity Export

Previous studies including LCGP 2005 and LCGP 2006 did not assume any significant increase of electricity exports. Moreover, the extensive expansion of transmission network which is taking place last years was not considered. The values of electricity export were estimated equal or slightly higher than actual in 2003-2004.

The recent changes and further planned expansion of transmission capabilities coupled with the already signed agreements create much better conditions for the new nuclear unit, specifically during the summer periods and off-peak hours.

Armenia already has a number of commitments of electricity supplies to Iran. The one, which is the most significant, is an «electricity for gas» agreement.

In May 2004, Armenia and Iran agreed on a long-term deal, under which Iran will supply natural gas to Armenia over 20 years starting in 2007, in exchange for electricity supplies from Armenia. As part of the deal, the two countries are building a gas pipeline at a cost of more than $200 million. Construction finally began in early 2005 on the long-awaited Iranian portion of the Iranian-Armenian pipeline financed by Iranian Bank of Export and Development. According to the agreement, the construction had to be completed by January 1, 2007. Currently, the expected commissioning date is postponed until the end of 2008.

Initially, Armenia will receive 1.3 billion cubic meters per year with plans to double the volume of imports by 2019. In exchange, Armenia will provide Iran with 3 kWh of electricity per cubic meter of gas. It means 3.9 billion kWh or approximately 500MW at the beginning and double amounts after the reasonable date of commissioning of a new nuclear power plant.

Although some of provisions of the official forecasts seems to be not very realistic and dependant on various reasons including political situation, the abovementioned agreement with Iran as can be considered as a given condition for analyses.

The forecasted export values according to the official GoA report prepared by the "Energy Research Institute" CJSC are summarized in a Table 4 below.

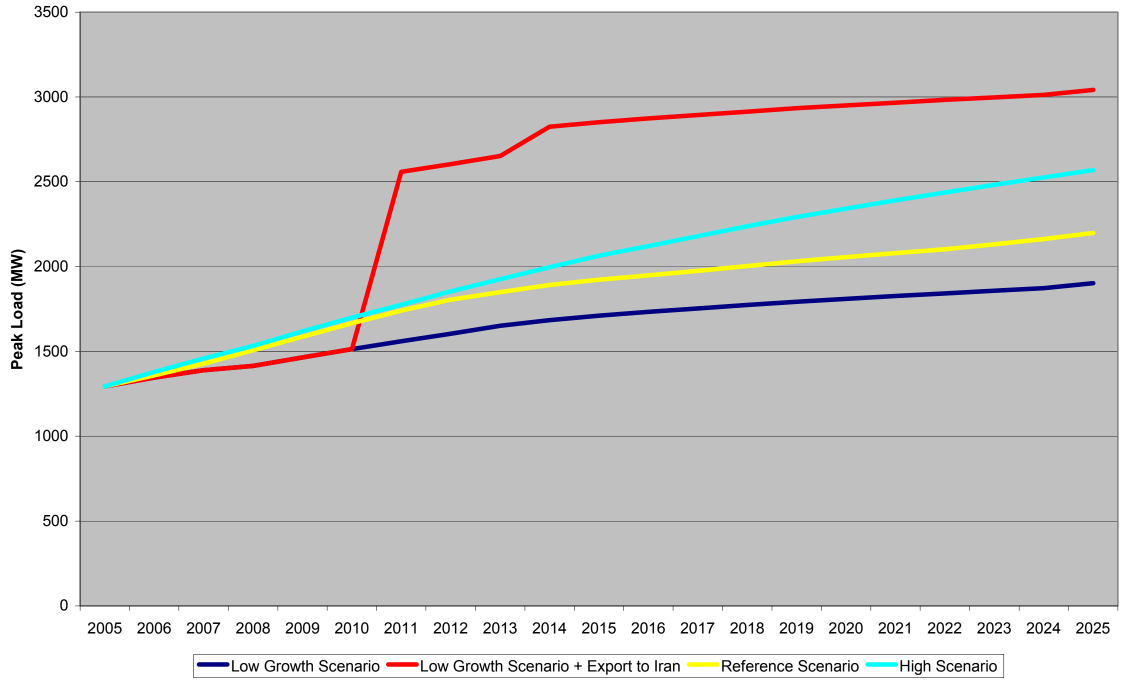
Table 4.

Planned Exports

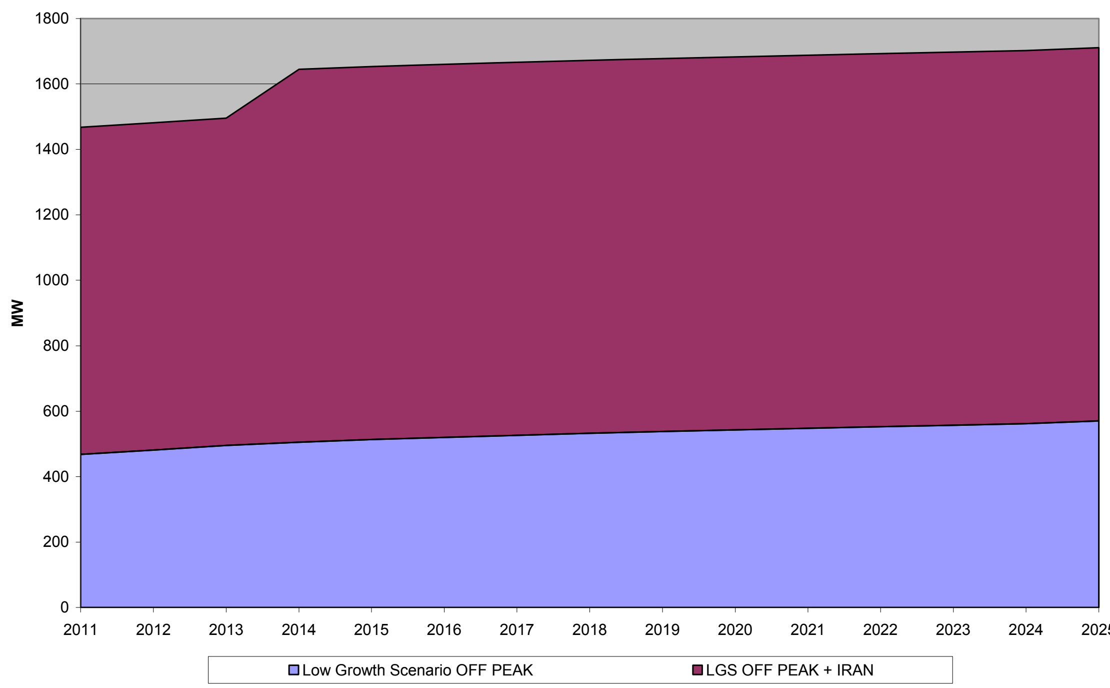
Interconnection	Planned Export Capacity (MW)	Time periods			
		2008 - 2010	2011 - 2013	2014 - 2015	2016 - 2020
Iran	**1140**	0	1000	1140	1140
including: 220 kV aerial HV transmission line from Mergi HPP	**140**	0	0	140	140
400 kV aerial HV transmission line from Hrazdan TPP	**1000**	0	1000	1000	1000
Georgia 400 kV aerial HV transmission line	**600**	600	600	600	600
Turkey 400 kV aerial HV transmission line	**500**	0	0	0	500
Total planned export capacities	**2240**	**600**	**1600**	**1740**	**2240**

Hence, the worst case to be considered at this stage can be based on the previously forecasted Low Growth Scenario with addition of committed exports to Iran starting 2011. This assumed Peak Load forecast is presented on a Chart 2 below.

Chart 2



It is worth noting that in case of Armenian power system and running a nuclear unit, the summer off-peaks load values have more significance. For the gross domestic consumption, according to dispatch logs, this ratio between annual system off-peak and peak is equal to about 0.27 - 0.3. The Chart 3 below shows the forecasted off-peak loads of Armenian Power System with added load of export to Iran.



Conclusions

- The dynamics and values of actual 2006-2007 peak and demand as well as the average growth rates are within the corridor between different Scenarios forecasted for 2005 and 2006 LCGPs. Previous modeling results[4] allowed running the new nuclear unit with the difference in commissioning date.
- Increase of electricity consumption by industrial consumers could eventually improve the annual and daily demand shapes which are important for new nuclear unit commissioning.
- Existing commitments and official forecast of electricity exports provide better conditions for new nuclear unit compared to those that were considered in previous LCGPs.
- Accurate modeling of the system to be performed within the scope of next stages to analyze least cost options and commissioning dates, long-term economic dispatch, reliability, and other issues.

[4] Modeling of the systems operational dispatch by IPM™ model within the scopes of LCGP 2005 and LCGP 2006

APPENDIX TO CHAPTER 4:
HIGH VOLTAGE NETWORK ASSESSMENT

1. Foreword

This report has been prepared according to the agreement with PA Consulting Group.

Steady-state and dynamic regimes of the Armenian Power System have been studied upon presence of the new ANPP 1000 MW unit in the perspective.

Measures have been suggested to maintain the system indicators in steady-state and dynamic regimes within allowed limits.

The study has been carried out using a software developed by Bonneville Power Administration, a company that serves the US Western Coast power system, and donated to the Armenian party within the frames of USAID assistance to Armenia.

The report consists of six chapters and four annexes.

Chapter one *includes description of the report structure.*

Chapter two *illustrates current condition of the Armenian Power System, designed equivalent scheme, as well as modeled values of the electric network elements.*

Chapter three *illustrates report initial data and main assumptions.*

Chapter four *summarizes steady-state regimes study results.*

Chapter five *summarizes dynamic regimes study results.*

Chapter six *summarizes main assumptions and suggestions of the report.*

Annex 1 *presents system equivalent scheme and its parameters.*

Annex 2 *includes software entry data.*

Annex 3 *presents steady-state regimes calculation results performed by the software.*

Annex 4 *presents dynamic regimes calculation results performed by the software.*

2. Existing High Voltage Network

The Armenian Power System (APS) is formed by 220-110 kV power transmission overhead lines (OL) and embraces the entire territory of the Republic. The only 330 kV OL line from Hrazdan TPP to Aghstafa (Azerbaijan) is out of operation at present. The network has a ring structure and high capacity that ensures reliable operation of the Armenian Power System and allows the implementation of electricity intrasystem flows as well as intersystem transitional power exchanges. Hrazdan TPP, the Armenian NPP, Shamb HPP and Spandaryan HPP directly transfer produced capacity to 220 kV network, the remaining major power stations are connected to 110 kV network. The system has fourteen 220 kV substations.

The model of equivalent replacement scheme of the Armenian Power System has been used in the study. Graphic illustration, numeration and titles of nodes, as well as OL parameters are given in Annex 1. The mentioned equivalent scheme includes all TPPs, the Armenian NPP, all stations of Sevan-Hrazdan and Vorotan Cascades of HPPs, all 220 kV OLs, all 220 kV substations and majority of 110 kV circular OLs. It should be noted that this scheme is consistent with the designed equivalent scheme used by the System Operator.

Annex 1 presents power stations' generators parameters of the equivalent scheme that have been used during the study of dynamic regimes.

Extreme admissible continuous values of OLs' capacities are given in Annex 1.

As it is seen from table A.1.4, Sipan OL (approx. 570 MW) and Yerevan OL (490 MW) have a maximum capacity. Another four 220 kV OLs (Erebouni TPP-1,2, Gougark-1,2 and Haghtanak) have approximately 300 MW capacity, the rest have less than 300 MW.

Installed capacities of 220/110 kV current (auto) transformers are given in table A.1.5 of Annex 1. At least two (auto) transformers are installed in all 220 kV substations that mainly ensure N-1 criteria.

The Armenian NPP and Ashnak's substations make an exception where there is only one (auto) transformer, but in both cases N-1 criteria is ensured by 110 kV significantly developed network.

3. Study Main Assumptions and Scenarios

3.1. LOAD LEVELS

Year 2007 has been selected as a base year for calculations. Capacity transfer by substations in winter maximum (31.12.2007 – 19:00) and summer minimum (18.06.2007 – 05:00) regimes have served as a basis for establishment of respective regimes for the considered forecasted years (2017 and 2030).
Year 2007 data have been provided by the Settlement Center and System Operator according to which the Armenian Power System internal consumption for the base year at a maximum regime amounted to 1180 MW and 359 MW at a minimum regime.

Based on the base year figures and initially provided forecasted consumption data, load volumes of system substations have been calculated for 2017 and 2030 by multiplying Year 2007 load numerical values with the following conversion factors.

$$k_{2017,max} = \frac{P_{2017,max}}{P_{2007,max}} = \frac{1563}{1180} \approx 1.3246\,,$$

$$k_{2017,min} = \frac{P_{2017,min}}{P_{2007,min}} = \frac{505}{360} \approx 1.4028\,,$$

$$k_{2030,max} = \frac{P_{2030,max}}{P_{2007,max}} = \frac{2211}{1180} \approx 1.8737\,,$$

$$k_{2030,\min} = \frac{P_{2017,\min}}{P_{2007,\min}} = \frac{714}{360} \approx 1.9833:$$

Capacity consumption distribution in substations for 2017 and 2030 are given in Annex 2.

Consideration of minimum regimes is required for the study of system's (over)loading regimes that is caused due to OL's incomplete loading. Another issue for a study is the operation conditions of the future 1000 MW NPP unit in minimum regimes.

Consideration of maximum regimes is required for the network load study.

It should be noted that the Armenian Power System minimum winter and maximum summer regimes are equivalent and are in the middle of the maximum and minimum.

3.2. GENERATION LEVELS

One of the peculiarities of the Armenian Power System is that total capacity output in a number of regimes is compatible with the ANPP capacity. This circumstance has a certain impact on the system operation especially in the minimum regimes.
Capacity output values in substations in the forecasted designed regimes, as well as system's existing produced capacities for the considered years are given in Annex 2.
For forecasted years it is accepted that system HPPs in summer minimum and winter maximum regimes produce as much capacity as in the respective regimes in 2007.

3.3. STUDY SCENARIOS

The following system steady-state regime (power flow) options (scenarios) have been viewed in the report.

Modelled Steady-State Regimes Scenarios

Scenario no.	*YEAR*	**Regime Title**	**Internal Demand, MW**	**Export to Iran, MW**
1.	2017	Maximum winter regime	1563	450
2.		Minimum summer regime	505	750
3.	2030	Maximum winter regime	2211	600
4.		Minimum summer regime	714	1000

In all years' scenarios it is accepted that there are no power exchanges with the Georgian Power System through existing (220 kV and 110 kV OLs), as well as future (400 kV OL) intersystem connections.

3.4. MODELING OF THE ARMENIAN POWER SYSTEM

Software modeling of high voltage electric network has been carried out for stability study with the use of a software package (SP) developed by Bonneville Power Administration, a company that serves the US Western Coast power system, and donated to the Armenian party within the frames of USAID assistance to Armenia.

The SP includes «Interactive Power Flow» (hereinafter IPF) and «Transient Stability Program» (hereinafter TSP) software.
The SP allows to use steady-state regime output data calculated by the IPF as entry data for TSP in order to study various emergency regimes. It should be noted that calculation algorithm used in this SP is rather stable against calculation data spreading and allows to study regimes that are even unallowable from the point of view of system real operation, but possible in theory.
IPF calculation results are given in diagrams where active power flow direction is marked by a pointer, and the number next to the pointer shows its value. Reactive power value and direction are given in brackets (if reactive power flow is opposite to active power direction, it is given as a negative number.
Node per unit (PU) voltage value is written under the node (the software allows the user to present voltage in nominal units). If it is deviated from ±5%, the node is given in grey and if the voltage is deviated from ±10%, the node is given in black.
The IPF also allows to control branches (lines and transformers) overloading. So, in case of lines overloading the current designed and admissible continuous values are written in Ampere (A) under the branch. If the overloaded branch is a transformer then the designed and nominal power values are written in MegaVolt Ampere (MVA) under the branch. Since different voltage levels of busbars and transformers of some substations have been modeled independently, then more than one node in the modeled scheme is compatible of the same substation.
The TSP calculation results are also presented in diagrams.
The report shows only the generator's relative angle (in our case compared with Hrazdan TPP) in degrees, generator active power in MW, generator reactive power in MVAR, generator bus voltage in PU and bus frequency deviation in Hertz. Time measurement unit is the cycle, which is equivalent to 0.02 seconds.

4. Steady state study results

4.1. SCENARIO 1

In scenario 1, system flow distribution calculation results are illustrated in picture A.3.1 of Annex 3.

As the calculation results show, certain problems appear in the Armenian Power System. They are as follows:

- ✓ Overloading of the ANPP's single (auto) transformer. In conditions of a maximum admissible continuous capacity of 200 MVA, (auto) transformer's capacity increases to 217 MVA.

- ✓ Overloading of 220 kV Sipan OL. Instead of admissible continuous 900 A the line transmits approximately 970 MVA.

- ✓ Voltage level in Zangezour distribution network is high from ±5%, but is within the allowable ±10% limits. Adjustment of voltage level in these nodes is carried out by changing position of pivots of (auto) transformers and generator voltages in that region. With this reason voltage level regulation special measures are not considered in this study.

Two options are suggested for solving of the above problems:

I. Install the second autotransformer in the ANPP substation and, simultaneously, “upgrade” the Sipan OL by changing the wire cut, or transform into an double-circuit OL, or build the second OL.

II. Build Armenian NPP-Hrazdan TPP 400 kV new OL.

Additional calculation of Scenario 1 has been carried out in case of presence of ANPP-Hrazdan TPP 400 kV new OL and the ANPP’s operation at full capacity (1000 MW), results of which are illustrated in fig. A.3.2 of Annex 3.

As seen from fig. A.3.2, in principle, all problems are resolved in this scenario, but loading of the existing autotransformer of the ANPP’s 220 kV substation is near the maximum admissible continuous limit (192 MVA, allowable limit is 200 MVA). In this circumstance the proposed installation of the second autotransformer remains in force.

4.2. SCENARIO 2

In Scenario 2, the system flow distribution calculation results are illustrated in fig. A.3.3 of Annex 3.

In 2017 it is impossible to ensure the system stability in case of ANPP’s full (1000 MW) loading. Allowable regime is ensured in case of 75% loading of the ANPP.

In this case, upon nonexistence of the ANPP-Hrazdan TPP 400 kV new OL, no significant problems appear in the system, but 220 kV Sipan OL’s loading is near the maximum allowable limit (817 A allowable instead of 900 A).

Additional calculation of Scenario 2 has been carried out in case of existence of the ANPP-Hrazdan TPP 400 kV new OL and ANPP’s operation at 75% capacity (750 MW), results of which are illustrated in fig. A.3.4 of Annex 3.

In this case, all problems disappear in the system.

4.3. SCENARIO 3

In Scenario 3, system flow distribution calculation results (upon nonexistence of ANPP-Hrazdan TPP 400 kV new OL) are illustrated in fig. A.3.5 of Annex 3.

There are certain problems in this Scenario, too. Sipan OL current reaches to 914 A, in case when the allowed limit is 900 A. The ANPP’s and Shahumyan-2 substation’s autotransformers get overloaded respectively to 273 MVA (allowable limit is 200 MVA) and 309 MVA (250 MVA). Another problem also appears with regard to Yerevan TPP’s Vinil, Kauchouk, Southern-1,2 and Nairit-1,2 110 kV OLs’ overloading.

Overloading of Sipan OL disappears in case of presence of the ANPP-Hrazdan TPP 400 kV new OL (Annex 3, fig. A.3.6), but the above mentioned autotransformers and 110 kV OLs remain overloaded.

4.4. SCENARIO 4

In Scenario 4 (without the ANPP – Hrazdan TPP 400 kV new OL) the system flow distribution calculation results are given in figure A.3.7 of Annex 3.

Sipan 220 kV OL is overloaded in this regime (1083 A instead of allowable 900 A), as well as Vinil, Kauchouk, Southern-1,2 and Nairit-1,2 110 kV OLs of Yerevan TPP.

And again, overloading of Sipan OL disappears in case of presence of the ANPP-Hrazdan 400 kV new OL (Annex 3, fig. A.3.8), but the above mentioned 110 kV OLs remain overloaded.

4.5. CONCLUSIONS AND RECOMMENDATIONS OF THE STEADY STATE ASSESSMENT STUDY

Thus, summarization of calculations made for the forthcoming 2017 and 2030 years shows that taking into consideration the following assumptions i.e.

- ✓ using designed values of forecasted loads transmission as compared with Year 2007,
- ✓ no capacity exchanges with the Georgian Power System,
- ✓ considering output level of main major HPPs for forecasted years stable and basic equivalent to Year 2007 output level,
- ✓ taking into account that equipment resources of all existing TPPs and the ANPP will be depleted in 2017 and removed from the Armenian Power System,

it is suggested:

- ⇨ **to build Armenian NPP – Hrazdan TPP 400 kV new OL** that will allow to avoid undesirable overloading in all considered scenarios. Only in Year 2030, during winter maximum regime, overloading is observed at Yerevan TPP's OLs, for elimination of which it is required to increase Vinil, Kauchouk, Southern-1,2 and Nairit-1,2 OLs' capacities (addition of wire cuts or construction of additional lines).
- ➡ In case of nonexistence of the **Armenian NPP – Hrazdan TPP 400 kV new OL** installation of an additional autotransformer at the ANPP's 200 kV substation is required, as well as increase of Sipan 220 kV OL's capacity using one of the following options: by adding wire cuts (in case additional load is ensured by the bearings), double-chain OL transformation or construction of the second parallel power transmission line. Capacity increase of Vinil, Kauchouk, Southern-1,2 and Nairit-1,2 OLs also remains in force (addition of wire cuts or construction of additional lines).

5. Stability Study Results

5.1. BACKGROUND

Main purpose of the stability study of the Armenian Power System is to disclose possible unwanted emergency situations during which dynamic regimes' parameters do not meet the stability requirements.

This study has been carried out for all four scenarios described in the previous chapter in case of the presence of the Armenian NPP-Hrazdan TPP 400 kV new OL. The study includes only modeling of the following two options of complicated types of emergency disturbances:

a. three-phase short circuit (SC) on the ANPP 220 kV busbars after 0.11 seconds, the ANPP disconnection along with SC disconnection and after another 0.12 seconds disconnection of Tabriz 400 kV OL,

b. three-phase SC on Hrazdan TPP 400 kV busbars after 0.11 seconds, disconnection of Tabriz 400 kV OL along with SC disconnection and after another 0.12 seconds disconnection of the ANPP.

Modeling of the above mentioned emergency situations is sufficient to study conditions for ensuring the Armenian Power System stations' synchronous operation and frequency allowable indicators (according to volume and duration) in dynamic regimes stipulated by the new ANPP 1000 MW unit capacity (as compared with entire system load).

Power stations' generator speed governors, as well as Underfrequency Load Shedding (ULS-I) equipment operations have also been modeled for calculations.

The following operations are carried out by the ULS-I in the Armenian Power System:

- ✓ It operates after 0.15 seconds from the moment when the system frequency reaches 48.6 Hz and a lower value,
- ✓ Each succession of the ULS-I starts at the system frequency reduction by 0.1 Hz.
- ✓ The entire system load is connected to the USL-I except for power stations own needs and VIP customers, in order to prevent frequency decrease starting from 46.6 Hz in complicated emergency situations. This means that the entire system load shall be disconnected by the 21st succession of the ULS-I operation.

The ULS-II is operated in the system as reserve automation for the ULS-I that ensures the following operations:

- ✓ It operates after 4.0 seconds from the moment when the system frequency reaches 48.6 Hz and remains in operation as long as it stays lower than the mentioned value,
- ✓ Each succession of the ULS-II starts operation in every 4.0 seconds,
- ✓ The entire system load is connected to the ULS-II except for power stations own needs and VIP customers in order to ensure frequency increase up to 48.6 Hz in 48 seconds.

Due to some restrictions in modeling, this study addresses operation of only ULS-I that has been modeled in five successions each with 20% disconnection possibility of system entire load. This approach is sufficient for having a general picture of dynamic regimes. ULS-II has not been modeled in order to avoid additional complications.

Calculation results are summarized in Annex 4.

5.2. SCENARIO 1.A

Calculations results of dynamic regime's option «**a**» of steady-state regime Scenario 1 are given in Annex 4.1.a.

The results show that relative angles of all station generators operating in the system (as compared with Hrazdan TPP) in this regime vibrate collectively and do not create a risk of an asynchronous regime.

The maximum electric power surge falls on Hrazdan TPP, but its vibration amplitude has a tendency to decline that eliminates the danger of turbine's unallowable acceleration. Level of stations' reactive capacity is within allowable limits, only Hrazdan TPP, as a balancing node, tries to consume the designed extra reactive capacity. Voltage levels are within short-term allowable limits and have a tendency to reach the normal level. Frequency decreases to 48.1 Hz and upon operation of ULS-I, it goes up without any complications.

Thus, the dynamic regime described in this scenario runs normally and prevents occurrence of post-emergency steady-state regime's unallowable conditions.

5.3. SCENARIO 1.B

Calculations results of dynamic regime's option «**b**» of steady-state regime Scenario 1 are given in Annex 4.1.b.

The results show that relative angles of all station generators operating in the system (as compared with Hrazdan TPP) in this regime vibrate collectively and do not create a risk of an asynchronous regime.

The maximum electric power surge again falls on Hrazdan TPP, but its vibration amplitude has a tendency to decline that eliminates the danger of turbine's unallowable acceleration. Level of stations' reactive capacity is within allowable limits, only Hrazdan TPP, as a balancing node, tries to consume the designed extra reactive capacity. Voltage levels are within allowable short-term limits and have a tendency to reach the normal level. Frequency decreases to 48.1 Hz and upon operation of ULS-I, it goes up without any complications.

Thus, the dynamic regime described in this scenario runs normally and prevents occurrence of post-emergency steady-state regime's unallowable conditions.

5.4. SCENARIO 2.A

Calculations results of dynamic regime's option «**a**» of steady-state regime Scenario 2 are given in Annex 4.2.a.

The results show that certain complications appear in the system in this regime. Relative angles of all station generators operating in the system (as compared with Hrazdan TPP) vibrate collectively except for Dzora HPP and Yerevan HPP that are approximately 140 cycles (2.8 seconds) left behind from synchronous operation regime with the system. It's not dangerous, since their output makes 2.5% of the entire system generation and, after running out of synchronous operation, their disconnection shall not lead to unwanted consequences. It should be noted that software calculations are stable and allow to assess certain indicators of the future regime. The maximum electric power surge again falls on Hrazdan TPP, but its vibration amplitude has a tendency to decline that eliminates the danger of turbine's unallowable acceleration. Level of stations' reactive capacity is within the allowable limits, only Hrazdan TPP as a balancing node, tries to consume the designed extra reactive capacity. Voltage levels are within short-term allowable limits (except for Dzora HPP's busbars that increases inadmissibly after approximately 420 cycles or 8.4 seconds, but before that the HPP must be disconnected) and have a tendency to reach the normal level. Frequency decreases to 46.6 Hz and upon operation of ULS-I, it goes up without any complications.

Thus, the dynamic regime described in this scenario shall run normally upon disconnection of Dzora HPP and Yerevan HPP and prevent occurrence of post-emergency steady-state regime’s unallowable conditions.

5.5. SCENARIO 2.B

Calculations results of dynamic regime’s option «**b**» of steady-state regime Scenario 2 are given in Annex 4.2.b.

The results show that relative angles of all station generators operating in the system (as compared with Hrazdan TPP) in this regime vibrate collectively and do not create a risk of an asynchronous regime.

The maximum electric power surge in this case falls on Hrazdan TPP and Yerevan TPP, but their vibration amplitude has a tendency to decline that eliminates the danger of turbine’s unallowable acceleration. Level of stations’ reactive capacity is within allowable limits, only Hrazdan TPP, as a balancing node, tries to consume the designed extra reactive capacity. Voltage levels are within short-term allowable limits and have a tendency to reach the normal level. Frequency decreases to 48.1 Hz and upon operation of ULS-I, it goes up without any complications.

Thus, the dynamic regime described in this scenario runs normally and prevents occurrence of post-emergency steady-state regime’s unallowable conditions.

5.6. SCENARIO 3.A

Calculations results of dynamic regime’s option «**a**» of steady-state regime Scenario 3 are given in Annex 4.3.a.

The results show that in this regime relative angles of all station generators operating in the system (as compared with Hrazdan TPP) vibrate collectively and do not create a risk of an asynchronous regime.

The maximum electric power surge in this case falls on Hrazdan and Yerevan TPPs, but their vibration amplitude has a tendency to decline that eliminates the danger of turbine’s unallowable acceleration. Level of stations’ reactive capacity is within the allowable limits, only Hrazdan TPP as a balancing node, tries to consume the designed extra reactive capacity. Yerevan TPP, in the beginning of a transient regime, produces certain amount of reactive capacity, but it decreases in the future and gains allowable levels. Voltage levels are within short-term allowable limits and have a tendency to reach the normal level. Frequency decreases to 48.1 Hz and upon operation of ULS-I, it goes up without any complications.

Thus, the dynamic regime described in this scenario runs normally and prevents occurrence of post-emergency steady-state regime’s unallowable conditions.

5.7. SCENARIO 3.B

Calculations results of dynamic regime's option «**b**» of steady-state regime Scenario 3 are given in Annex 4.3.b.

The results show that in this regime relative angles of all station generators operating in the system (as compared with Hrazdan TPP) vibrate collectively and do not create a risk of an asynchronous regime. The maximum electric power surge in this case falls on Hrazdan and Yerevan TPPs, but their vibration amplitude has a tendency to decline that eliminates the danger of turbine's unallowable acceleration. Level of stations' reactive capacity is within allowable limits, only Hrazdan TPP, as a balancing node, tries to consume the designed extra reactive capacity. Yerevan TPP, in the beginning of a transient regime, produces certain amount of reactive capacity, but it decreases in the future and gains allowable levels. Voltage levels are within short-term allowable limits and have a tendency to reach the normal level. Frequency decreases to 48.0 Hz and upon operation of ULS-I, it goes up rather quickly without any complications.

Thus, the dynamic regime described in this scenario runs normally and prevents occurrence of post-emergency steady-state regime's unallowable conditions.

5.8. SCENARIO 4.A

Calculations results of dynamic regime's option «**a**» of steady-state regime scenario 4 are given in Annex 4.4.a.

The results show that certain complications appear in the system in this regime as well. Relative angles of all station generators operating in the system (as compared with Hrazdan TPP) vibrate collectively except for Dzora HPP and Yerevan HPP that are approximately 160 cycles (3.2 seconds) left behind from synchronous operation regime with the system. It's not dangerous, since their output makes 1.0% of entire system generation and after running out of synchronous operation, their disconnection shall not lead to unwanted consequences. It should be noted that software calculations are stable and allow to assess certain indicators of the future regime. The maximum electric power surge falls on Hrazdan TPP, but its vibration amplitude has a tendency to decline that eliminates the danger of turbine's unallowable acceleration. Level of stations' reactive capacity is within allowable limits, only Hrazdan TPP, as a balancing node, tries to consume the designed extra reactive capacity. Voltage levels, after certain major vibrations, are within short-term allowable limits and have a tendency to reach the normal level. Frequency decreases to 47.0 Hz and upon operation of ULS-I, it goes up without any complications.

Thus, the dynamic regime described in this scenario shall run normally upon disconnection of Dzora HPP and Yerevan HPP and prevent occurrence of post-emergency steady-state regime's unallowable conditions.

5.9. SCENARIO 4.B

Calculations results of dynamic regime's option «**b**» of steady-state regime Scenario 4 are given in Annex 4.4.b.

The results show that certain complications appear in the system in this regime as well. Relative angles of all station generators operating in the system (as compared with Hrazdan TPP) vibrate collectively except for Dzora HPP and Yerevan HPP that are approximately 170 cycles (3.4 seconds) left behind from synchronous operation regime with the system. It's not dangerous, since their output makes 1.0% of the entire system generation and, after running out of synchronous operation, their disconnection shall not lead to unwanted consequences. It should be noted that in this case also software calculations are stable and allow to assess certain indicators of the future regime. The maximum electric power surge falls on Hrazdan TPP, but its vibration amplitude has a tendency to decline that eliminates the danger of turbine's unallowable acceleration. Level of stations' reactive capacity is within allowable limits, only Hrazdan TPP, as a balancing node, tries to consume the designed extra reactive capacity. Voltage levels, after certain major vibrations, are within short-term allowable limits and have a tendency to reach the normal level. Frequency decreases to 47.0 Hz and upon operation of ULS-I, it goes up without any complications.

Thus, the dynamic regime described in this scenario shall run normally upon disconnection of Dzora HPP and Yerevan HPP and prevent occurrence of post-emergency steady-state regime's unallowable conditions.

5.10. CONCLUSIONS AND RECOMMENDATIONS OF THE STABILITY STUDY

Summarizing calculation results of dynamic regimes for the forthcoming 2017 and 2030, the following should be noted:

- The Armenian power system has a rather good potential to withstand emergency regimes.
- Voltage levels in all considered dynamic regimes are within short-term allowable limits and have a tendency to reach the post-emergency allowable level.
- Level of reactive capacities of stations is within allowable limits.
- Frequency, in the worst case, drops to the allowable 46.6 Hz and upon operation of ULS-I, it goes up without any complication.

6. Final Conclusions and Recommendations

Main conclusions are the following:

- It is impossible to load the ANPP at full 1000 MW capacity only in 2017 summer minimum regime.
- The Armenian Power System has a rather good potential to withstand emergency regimes.
- Voltage levels in dynamic regimes are within short-term allowable limits and have a tendency to reach the post-emergency allowable level.
- Level of stations' reactive capacities is within allowable limits.
- Frequency, in the worst emergency case, decreases to the allowable 46.6 Hz limit and upon operation of ULS-I, it goes up without any complication.

Main recommendations are:

⇨ It is required to **build the ANPP-Hrazdan TPP 400 kV new OL**, the presence of which shall avoid overloading of OLs and (auto) transformers. Overloading is observed at Yerevan TPP's Vinil, Kauchouk, Southern-1,2 and Nairit-1,2 OLs only in

2030 maximum winter regime, for elimination of which it is required to increase the OLs' capacities.

⇨ Upon nonexistence of the **ANPP-Hrazdan TPP 400 kV new OL,** installation of an additional autotransformer at the ANPP 220 kV substation is required, as well as increase of capacities of Sipan 220 kV, Vinil, Kauchouk, Southern-1,2 and Nairit-1,2 110 kV OLs.

⇨ Disconnection of **Dzora HPP and Yerevan HPP** in 2.8 seconds during their asynchronous operation must be envisioned.

List of Abbreviations

A – Ampere

NPP – Nuclear Power Plant

USA – United States of America

TSP – Dynamic Regimes Program

PS – Power System

SP – Software Package

SC – Short Circuit

kV – Kilovolt

FAO – Frequent Automated Off-loading

ANPP – Armenian Nuclear Power Plant

IPF – Flow Distribution Program

HPP – Hydraulic (hydro) Power Plant

RoA – Republic of Armenia

MVA – MegaVolt Ampere

MVAr – MegaVolt Ampere - reactive

MW – Megawatt

TPP – Thermal Power Plant

OL – (Power transmission) Overhead Line

Appendix 1. The Scheme of Armenian High Voltage Network

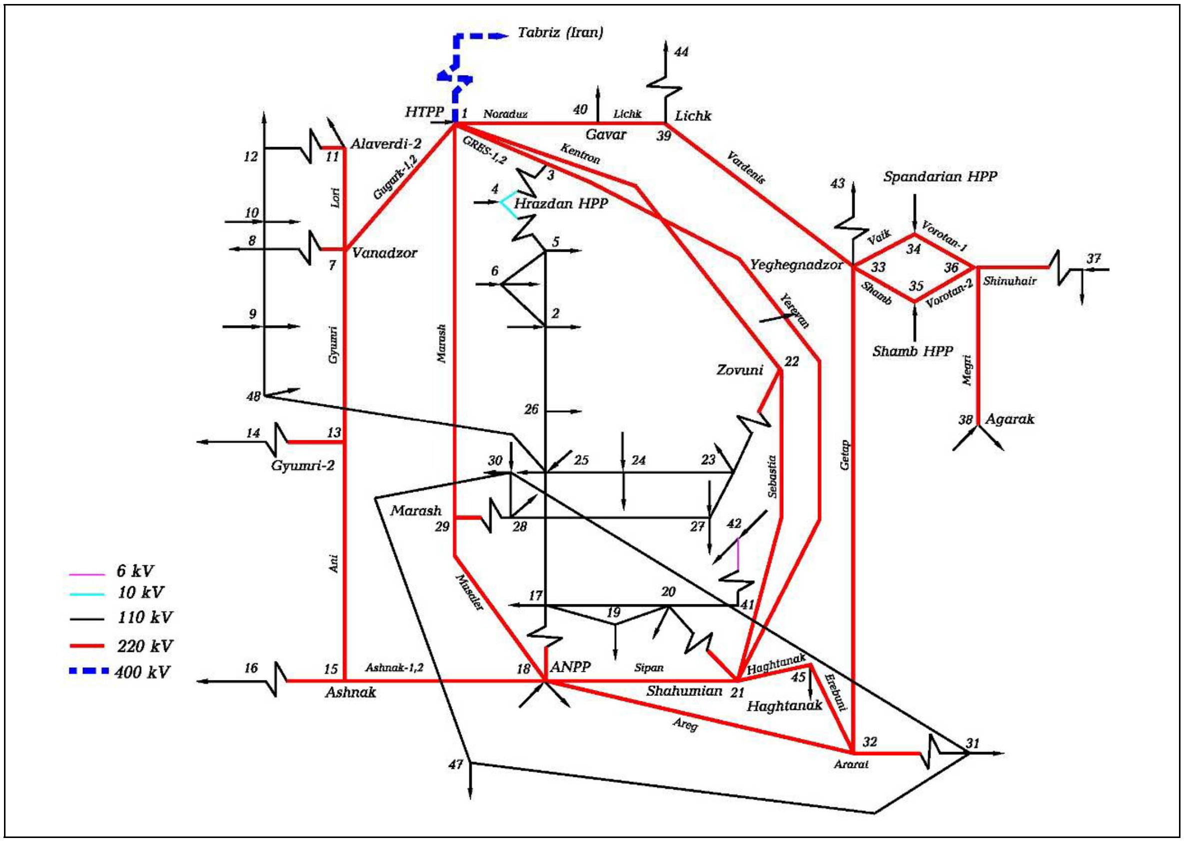


FIG. A.1.1 The Equivalent Scheme of the Armenian Power System

Table A.1.1 The Node Names of the Equivalent Scheme of the Armenian PS

1. Hrazdan TPP (unit part)	17. Armenian NPP-110	33. SS Yeghegnadzor
2. Hrazdan TPP (CHP part)	18. Armenian NPP-220	34. Spandaryan HPP
3. SS Hrazdan HPP-220	19. SS Echmiadzin	35. Shamb HPP
4. SS Hrazdan HPP	20. SS Shahumyan-110	36. SS Shinuhayr
5. SS Hrazdan HPP-110	21. SS Shahumyan-220	37. Tatev HPP
6. Sevan HPP	22. SS Zovuni-220	38. SS Agarak
7. SS Vanadzor-220	23. SS Zovuni-110	39. SS Lichk
8. SS Vanadzor-110	24. Arzni HPP	40. SS Kamo
9. SS Vanadzor TPP	25. Argel HPP	41. Yerevan HPP-110
10. Dzora HPP	26. SS Charencavan	42. Yerevan HPP-6
11. SS Alaverdi-220	27. Kanaker HPP	43. SS Yeghegnadzor-110
12. SS Alaverdi-110	28. SS Marash-110	44. SS Lick-110
13. SS Gyumri-220	29. SS Marash-220	45. SS Haghtanak-220
14. SS Gyumri-110	30. Yerevan TPP (CHP)	46. Tbilisi TPP
15. SS Ashnak-220	31. SS Ararat-110	47. SS Mkhchyan-110
16. SS Ashnak-110	32. SS Ararat-220	48. SS Spitak-110

Table A.1.2. Link Parameters (High Voltage Lines)

Nodes		R	X	B	KT	Name
01	03	0.362	02.320	-068.78E-06	0.0000	GRES-1,2
01	07	1.403	09.166	-262.5E-06	0.0000	Gugark-1,2
01	22	4.246	22.967	-152.9E-06	0.0000	Kentron
01	29	4.719	25.523	-169.9E-06	0.0000	Marash
01	40	4.795	19.410	-124.7E-06	0.0000	Noraduz
02	05	1.893	03.942	-025.4E-06	0.0000	Hankavan
02	06	3.828	07.971	-051.4E-06	0.0000	Akhtamar
02	26	3.291	06.853	-044.2E-06	0.0000	Solak
03	04	1.128	33.155	+000.00000	0.0434	SS HrazdanHPP
03	21	2.466	17.871	-158.9E-06	0.0000	Yerevan
05	04	0.163	04.888	+000.0000	0.0868	SS HrazdanHPP
05	06	4.109	08.856	-053.3E-06	0.0000	Sevan
07	08	0.300	27.190	+000.00000	0.5050	SS Vanadzor
07	13	5.976	32.321	-215.2E-06	0.0000	Gjumri
07	11	4.852	20.269	-133.8E-06	0.0000	Lori
08	09	0.059	00.128	-003.1E-06	0.0000	TPP-1,2
08	10	2.190	04.730	-113.7E-06	0.0000	Vahagn-1,2 to DzoraHPP
09	48	1.95	3.89	-100.0E-06	0.0000	Archut-1,2
10	12	2.290	04.491	-118.9E-06	0.0000	Vahagn-1,2
11	12	1.095	50.870	+000.0000	0.4945	SS Alaverdi
11	46	6.29	26.5	-170.0E-06	0.0000	Alaverdi
13	14	0.285	23.750	+000.0000	0.5050	SS Gyumri
13	15	4.129	21.532	-154.2E-06	0.0000	Ani

Nodes		R	X	B	K_T	Name
15	16	1.312	101.40	+000.0000	0.4787	SS Ashnak
15	18	1.455	07.866	-209.4E-06	0.0000	Ashnak-1,2
17	19	5.341	11.520	-069.3E-06	0.0000	Echmiadzin
17	25	9.93	21.070	-130.8E-06	0.0000	Bjni
18	17	0.554	29.770	+000.0000	0.5261	SS ArmenianNPP
18	21	1.230	9.357	-091.8E-06	0.0000	Sipan
18	29	4.412	23.458	-161.6E-06	0.0000	Musaler
18	32	6.459	34.345	-236.5E-06	0.0000	Areg
19	20	2.717	05.856	-035.21E-06	0.0000	Shahumian-1
20	41	0.738	01.590	-038.25E-06	0.0000	Karmir-1,2
21	20	0.300	27.930	+000.0000	0.5156	SS Shahumian
21	22	1.484	7.737	-055.4E-06	0.0000	Sebastia
32	45	4.610	26.120	-181.9E-06	0.0000	Erebuni
22	23	0.300	22.760	+000.0000	0.5050	SS Zovuni
23	24	0.410	0.880	-036.4E-06	0.0000	Arinj, Hrazdan
23	27	0.199	0.507	-013.0E-06	0.0000	Kanaker
24	25	1.32	2.84	-068.3E-06	0.0000	Arinj, Hrazdan
25	26	0.798	1.72	-041.4E-06	0.0000	Khachsi
27	28	1.543	4.010	-099.1E-06	0.0000	Zejtun-1,2
28	30	0.640	1.80	-069.4E-06	0.0000	Vinil, Kauchuk, Haravain-1,2, Nairit-1,2
29	28	0.420	22.130	+000.0000	0.5156	SS Marash
30	47	0.0014	16.6	-112.0E-06	0.0000	Ayntap, Masis, Kapuyt Lich-1,2
31	47	4.6	16.1	-110.0E-06	0.0000	Ararat-1
32	31	1.340	52.270	+000.0000	0.5198	SS Ararat

Nodes		R	X	B	K_T	Name
32	33	4.970	26.425	-182.0E-06	0.0000	Getap
30	31	4.8	16.6	-104.0E-06		Ararat-2
33	34	7.266	29.414	-189.0E-06	0.0000	Vaik
33	35	6.782	36.678	-244.2E-06	0.0000	Shamb
33	39	4.773	19.719	-124.1E-06	0.0000	Vardenis
34	36	4.271	17.287	-111.1E-06	0.0000	Vorotan-1
35	36	1.639	08.863	-059.0E-06	0.0000	Vorotan-2
36	37	1.487	33.740	+000.0000	0.4756	SS Shinuhair
36	38	6.278	33.956	-226.0E-06	0.000	Megri
39	40	2.600	10.524	-067.6E-06	0.0000	Lichk
41	42	0.686	17.091	+000.0000	0.0548	SS YerevanHPP
21	45	0.176	01.130	-008.4E-06	0.0000	Haghtanak
17	20	6.558	13.910	-086.4E-06	0.0000	Shahumian-2
33	43	1.305	51.321	+000.0000	0.4866	SSYeghegnadzor
39	44	2.537	50.842	+000.0000	0.5008	SS Lichk

Table A.1.3. Parameters of existing Generators the Armenian Power System

Power Plant	U_{nom}, kV		P_{unit},	X'_d, Ohm	M_j, MWs
	Gen.	Netw.	item x MW	(for 1 unit)	(for 1 unit)
Hrazdan TPP	15.75	220	3 x 200	66.14	1479.6
	15.75	220	1 x 210	66.14	1479.6
	6.3	110	2 x 50	45.11	413.1
	10.5	220	2 x 100	108.43	784.2
Yerevan TPP	6.3	110	5 x 50	45.12	411.8
	18.0	110	2 x 150	20.83	1139.3
Vanadzor TPP	6.3	110	1 x 25	76.80	224.4
	6.3	110	2 x 12	140.24	96.2
	6.3	110	1 x 50	42.38	411.8
Sevan HPP	10.5	110	2 x 17.5	182.08	136.5
Hrazdan HPP	10.5	10.5	2 x 41	0.832	377.2
Argel HPP	10.5	110	4 x 57.5	39.07	575.0
Arzni HPP	10.5	110	3 x 24.4	98.01	224.4
Kanaker HPP	11.0	110	4 x 13.25	146.00	128.5
	10.5	110	2 x 27	104.26	235.1
Yerevan HPP	6.3	6.3	2 x 22.5	0.433	194.6
Spandarian HPP	10.5	220	2 x 38	234.43	304.4
Shamb HPP	13.8	220	2 x 87.6	126.57	708.2
Tatev HPP	10.5	110	3 x 54.4	51.59	329.2
Armenian NPP	15.75	220	2 x 220	54.24	2912.8

Table A.1.4. Rates of the HVL-220 kV of the Armenian Power System (cosφ = 0.9)

NN	Name	Rate [MW]	NN	Name	Rate [MW]
1.	GRES-1,2	658	13.	Kentron	285
2.	Gugark-1,2	658	14.	Marash	285
3.	Sipan	569	15.	Musaler	285
4.	Ashnak-1,2	566	16.	Sebastia	285
5.	Yerevan	487	17.	Shamb	285
6.	Erebuni	329	18.	Vorotan-2	285
7.	Haghtanak	329	19.	Ani	283
8.	Lichk	295	20.	Megri	283
9.	Noraduz	295	21.	Lori	243
10.	Areg	285	22.	Vorotan-1	243
11.	Getap	285	23.	Vaik	233
12.	Gyumri	285	24.	Vardenis	233

Table A.1.5. Rates of the Equipment ([Auto]transformers 220/110 kV)

NN	Name	Unit x Rate [MVA]	Total Rate [MVA]
1.	Hrazdan HPP	2x120	240
2.	SS Vanadzor	2x125	250
3.	SS Alaverdi	2x63	126
4.	SS Gyumri	2x125	250
5.	SS Ashnak	1x63	63
6.	SS ANPP	1x200	200
7.	SS Shahumian	2x125	250
8.	SS Zovuni	2x125	250
9.	SS Marash	1x250, 1x125	375
10.	SS Ararat	2x63	126
11.	SS Shinuhair	3x63	189
12.	SS Yeghegnadzor	2x63	126
13.	SS Lichk	2x63	126

Appendix 2. Input data

Table A.2.1. The power plants generation and Substations load

No	Name	Voltage, kV	31.12.2007 19:00		18.06.2007 05:00		2017–MAX		2017-MIN		2030–MAX		2030–MIN	
			P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW
1	HrazdanTPP (unit part)	220	315.73		0.0									
2	HrazdanTPP (CHP part)	110	0.0	34.79	0.0	2.83		46.08		3.96		65.19		5.6
3	HrazdanHPP	220												
4	HrazdanHPP	10	0.0		0.0									
5	HrazdanHPP	110		75.05		17.35		99.41		24.34		140.62		34.41
6	SevanHPP	110	0.0	16.31	0.0	2.64		21.6		3.7		30.56		5.24
7	Vanadzor-2	220												
8	Vanadzor-2	110		41.44		2.23		54.89		3.13		77.65		4.42
9	VanadzorTPP	110	0.0	1.04	0.0	0.02		1.38		0.03		1.95		0.04
10	DzoraTPP	110	5.21	0.44	12.20	1.27		0.58		1.78		0.82		2.52
11	Alaverdi-2	220												
12	Alaverdi-2	110		45.24		2.32		59.92		3.25		84.77		4.6
13	Gyumri-2	220												
14	Gyumri-2	110		65.45		9.63		86.7		13.51		122.63		19.1
15	Ashnak	220												
16	Ashnak	110		22.54		10.02		29.86		14.06		42.23		19.87
17	ArmenianNPP	110		65.19		25.66		86.35		36		122.15		50.89
18	ArmenianNPP	220	382.60	17.6	349.0	17.59		23.31		24.68		32.98		34.89

No	Name	Voltage, kV	31.12.2007 19:00		18.06.2007 05:00		2017–MAX		2017-MIN		2030–MAX		2030–MIN	
			PG, MW	Pc, MW	PG, MW	Pc, MW	PG, MW	Pc, MW	PG, MW	Pc, MW	PG, MW	Pc, MW	PG, MW	Pc, MW
19	Echniadzin	110		34.95		17.81		46.29		24.98		65.49		35.32
20	Shahumyan-2	110		186.90		44.59		247.57		62.55		350.19		88.44
21	Shahumyan-2	220												
22	Zovuni	220												
23	Zovuni	110		34.4		7.38		45.57		10.35		64.46		14.64
24	ArzniHPP	110	24.52	9.44	4.59			12.5				17.69		
25	ArgelHPP	110	48.05	2.07	0.0	5.11		2.74		7.17		3.88		10.13
26	Charencavan-3	110		19.28		5.7		25.54		8		36.12		11.3
27	KanakerHPP	110	45.41	22.44	4.79	14.83		29.72		20.8		42.05		29.41
28	Marash	110		108.89		36.34		144.24		50.97		204.03		72.07
29	Marash	220												
30	YerevanCHP	110	45.85	51.34	0.0	38.11		68		53.46		96.2		75.58
31	Ararat-2	110		126.7		15.8		167.83		22.16		237.4		31.34
32	Ararat-2	220												
33	Yeghegnadzor	220												
34	SpandaryanHPP	220	47.19		0									
35	ShambHPP	220	70.69		0									
36	Shinuhayr	220												
37	TatevHPP	110	115.93	118.19	50.0	57.96		156.55		81.31		221.45		114.95
38	Agarak-2	220	52.75			71.77				71.77				71.77
39	Lichk	220												

No	Name	Voltage, kV	31.12.2007 19:00		18.06.2007 05:00		2017–MAX		2017-MIN		2030–MAX		2030–MIN	
			P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW	P_G, MW	P_C, MW
40	Gavar	220		12.83		4.91		16.99		6.89		24.04		9.74
41	YerevanHPP	110												
42	YerevanHPP	6	26.40	16.39	5.77	5.73		21.71		8.04		30.71		11.36
43	Yeghegnadzor	110		11.36		3.15		15.05		4.42		21.29		6.25
44	Lichk	110		19.43		3.29		25.74		4.62		36.41		6.53
45	Haghtanak	220		4.01		0.73		5.31		1.02		7.51		1.45
46	TbilisiTPP	220	0.0		0.0									
47	Mkhchyan-2	110		9.67		5		12.81		7.01		18.12		9.92
48	Spitak	110		6.6		2		8.74		2.81		12.37		3.97
51	HrazdanHPP Transformers Midpoint	-												
	Total			1179.98		431.77		1563		576.77		2210.93		785.75

Table A.2.2. Installed and Available capacities of generators in 2017 and 2020

Name of Power Plant	Unit x Installed Capacity (Cumulative), #xMW	Available capacity	
		Winter max	Summer min
2017			
Armenian NPP	1x1000	1000	1000
Yerevan TPP (CHP)	1x241	241	241
Hrazdan TPP	1x440	440	440
Sevan-Hrazdan HPP Cascade	550	145	235
Vorotan HPP Cascade	400	400	400
Renewable (incl. small HPP)	80	20	42
TOTAL		***2246***	***2358***
2030			
Armenian NPP	1x1000	1000	1000
Yerevan TPP (CHP)	2x241	282	282
Hrazdan TPP	1x440+1x400	440	440
Sevan-Hrazdan HPP Cascade	550	145	235
Vorotan HPP Cascade	400	400	400
Renewable (incl. small HPP)	80	20	42
TOTAL		***2287***	***2399***

Appendix 3. Steady state study results

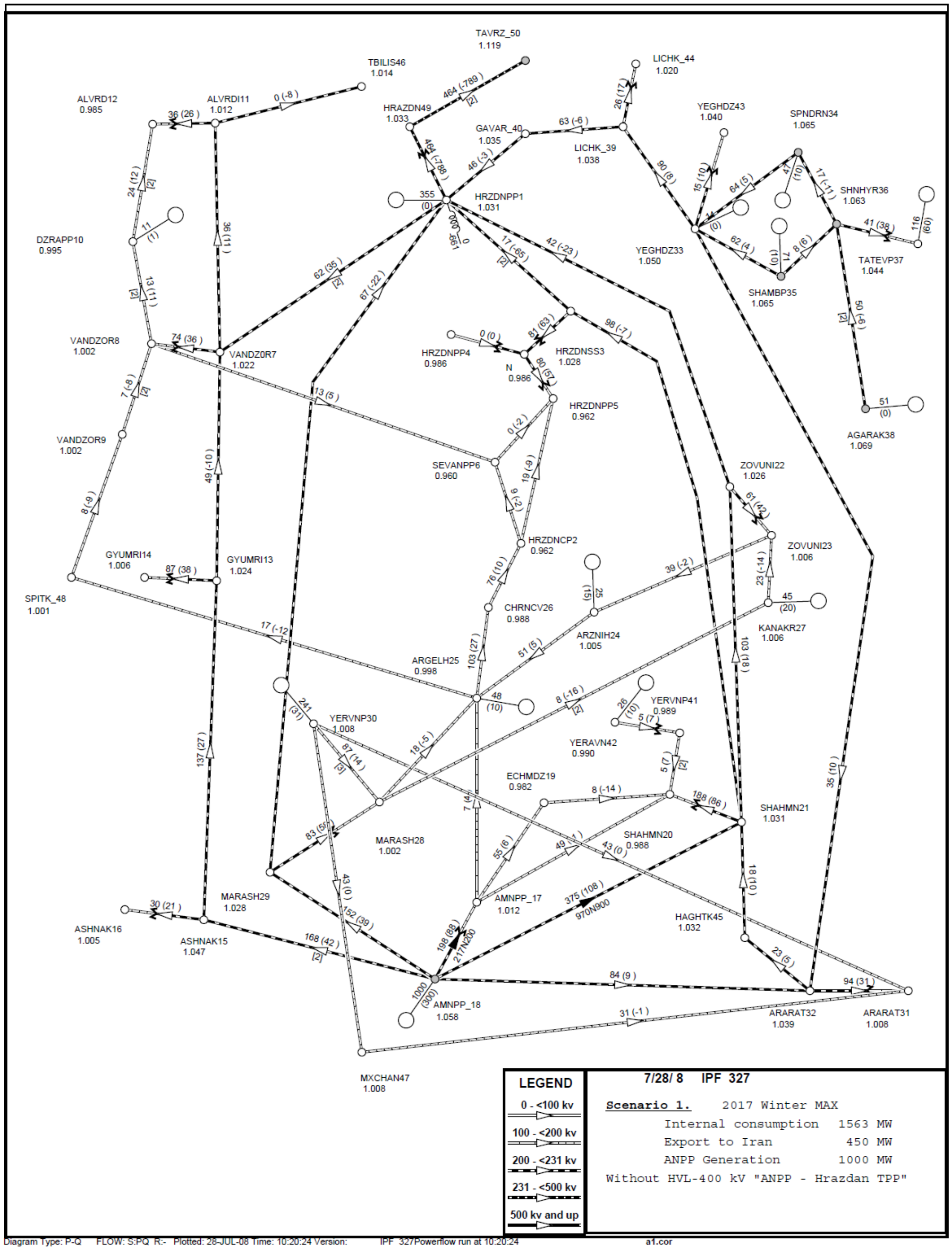


FIG A.3.1. Scenario 1. 2017 Winter max Regime without HVL-400 kV ANPP-Hrazdan TPP

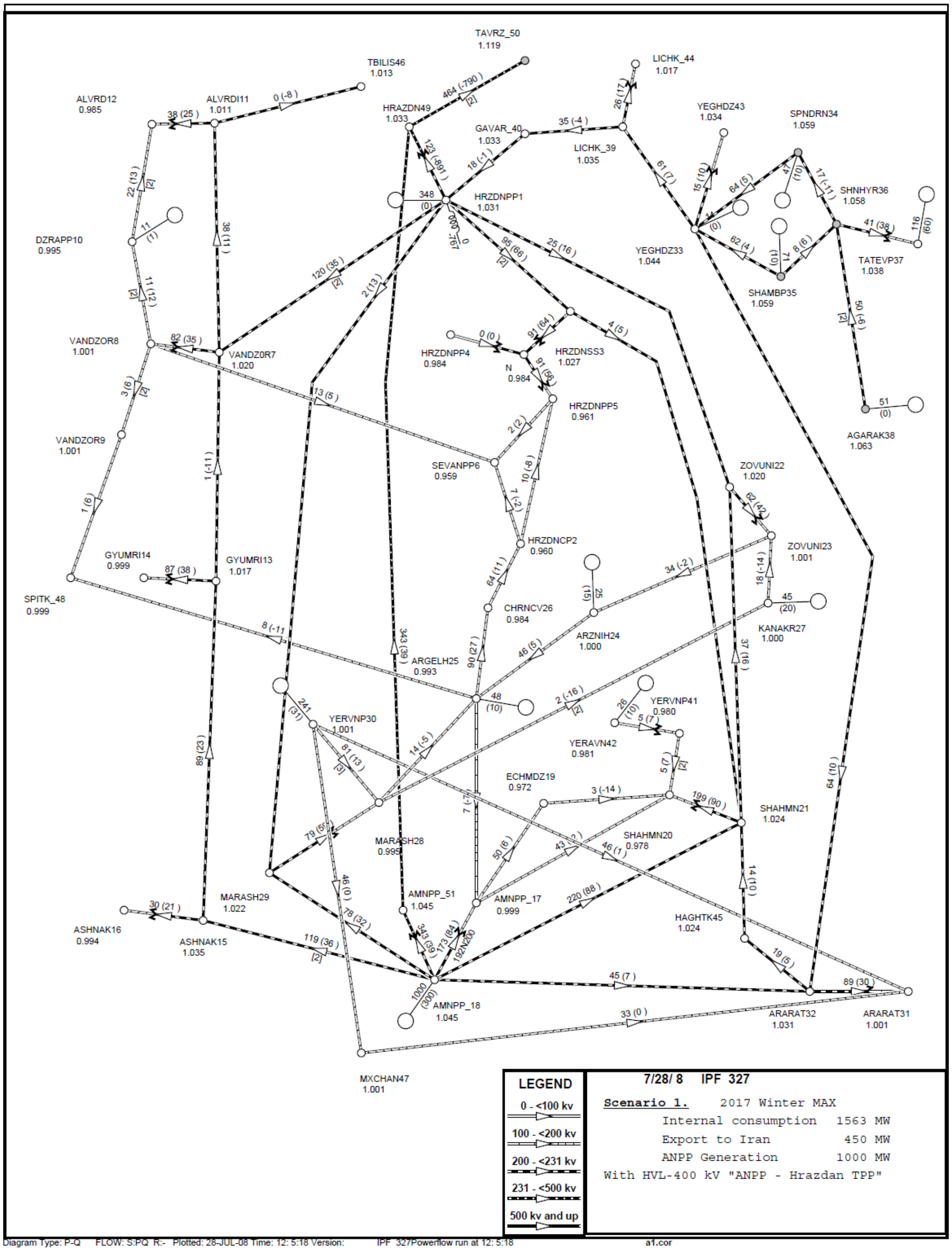


FIG A.3.2. Scenario 1. 2017 Winter max Regime with HVL-400 kV ANPP-Hrazdan TPP

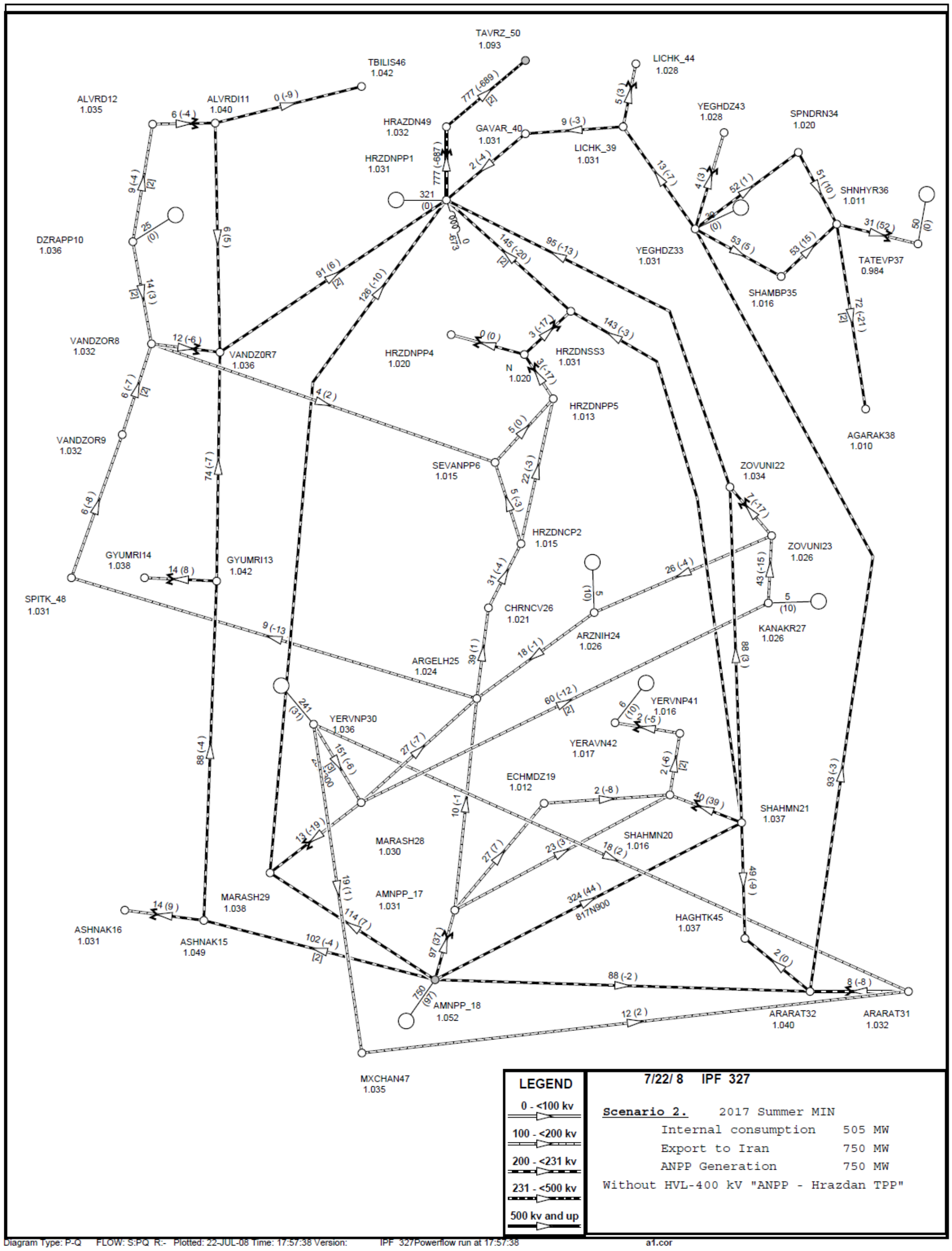


FIG A.3.3. Scenario 2. 2017 Summer min Regime without HVL-400 kV ANPP-Hrazdan TPP

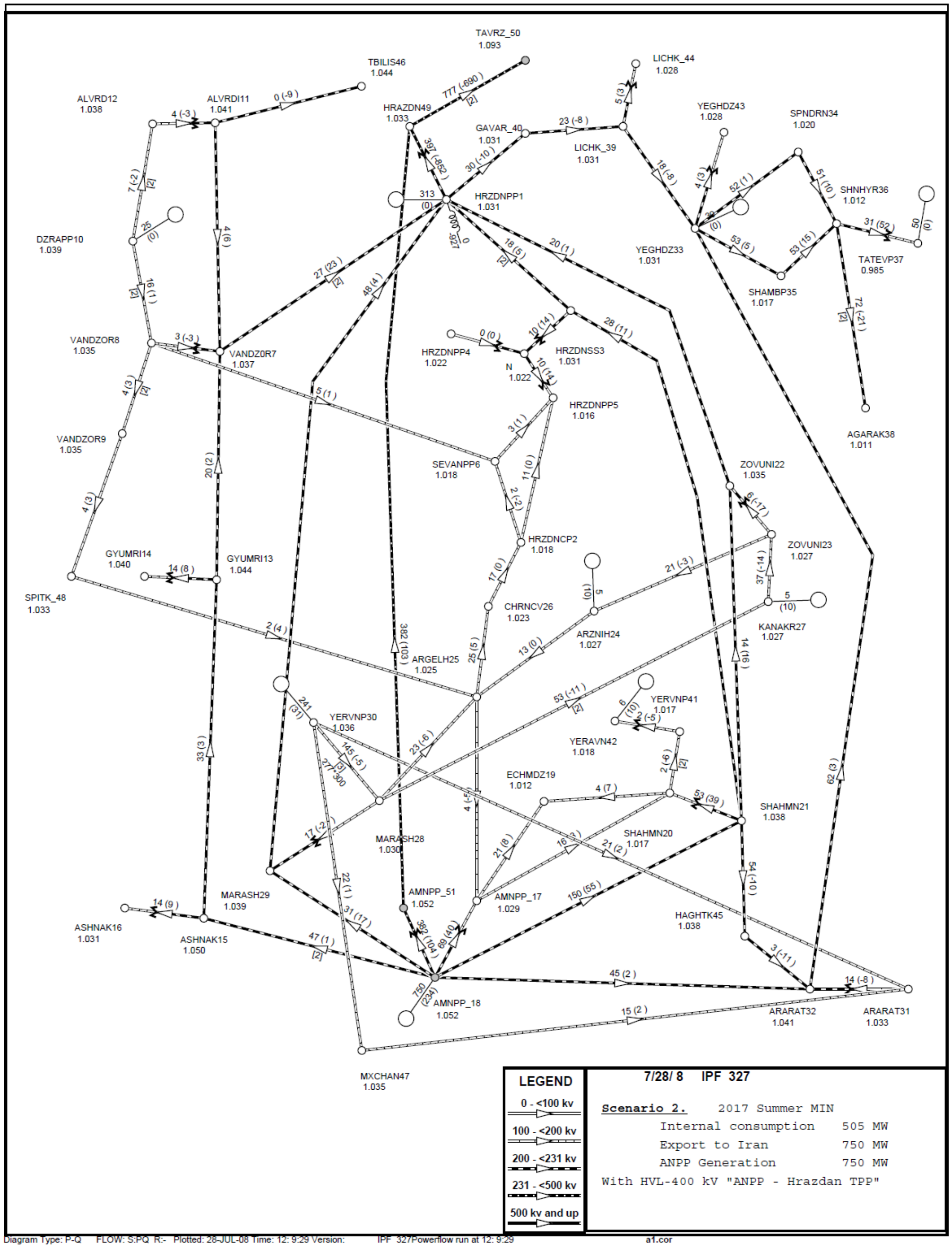


FIG A.3.4. Scenario 2. 2017 Summer min Regime with HVL-400 kV ANPP-Hrazdan TPP

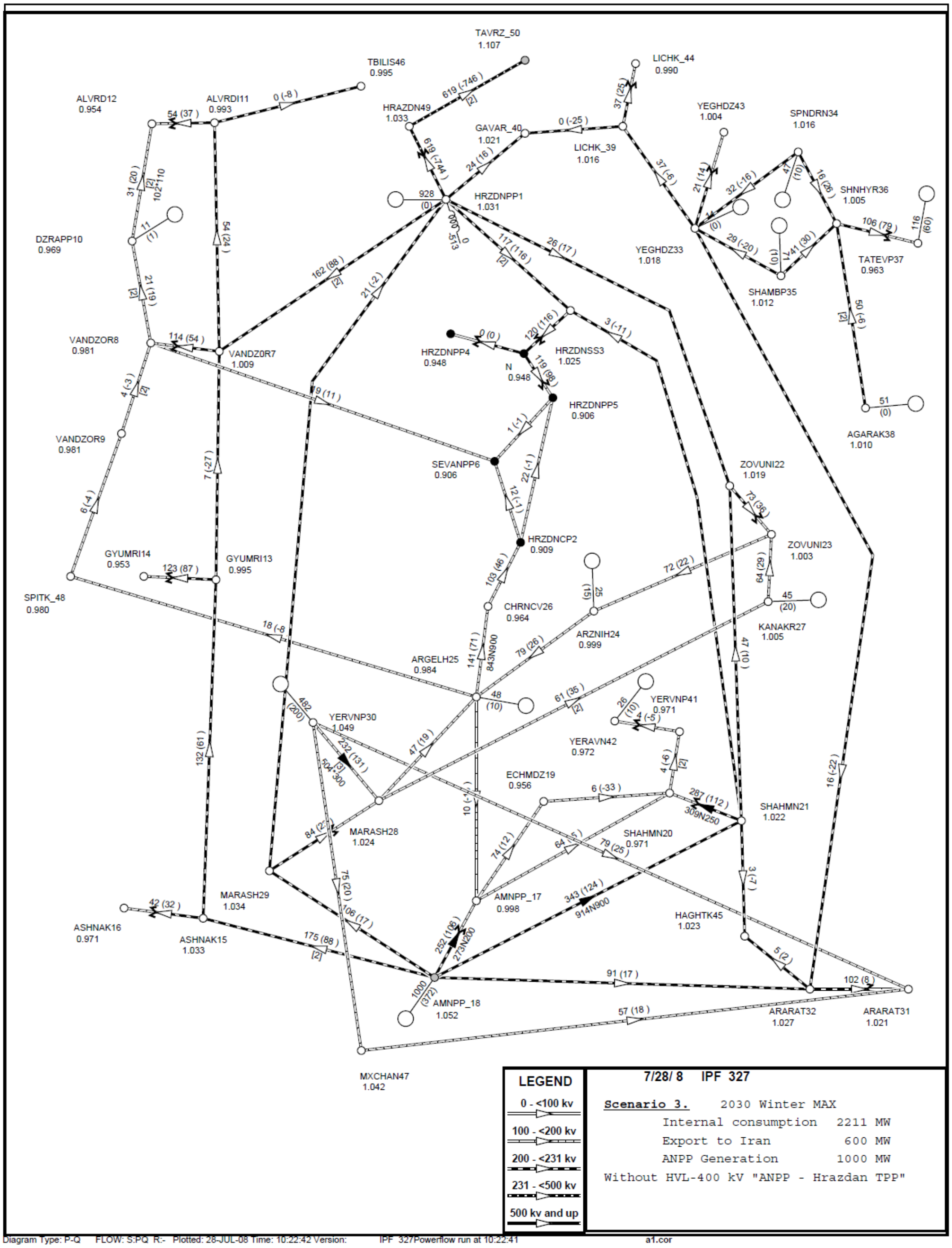


FIG A.3.5.Scenario 3. 2030 Winter max Regime without HVL-400 kV ANPP-Hrazdan TPP

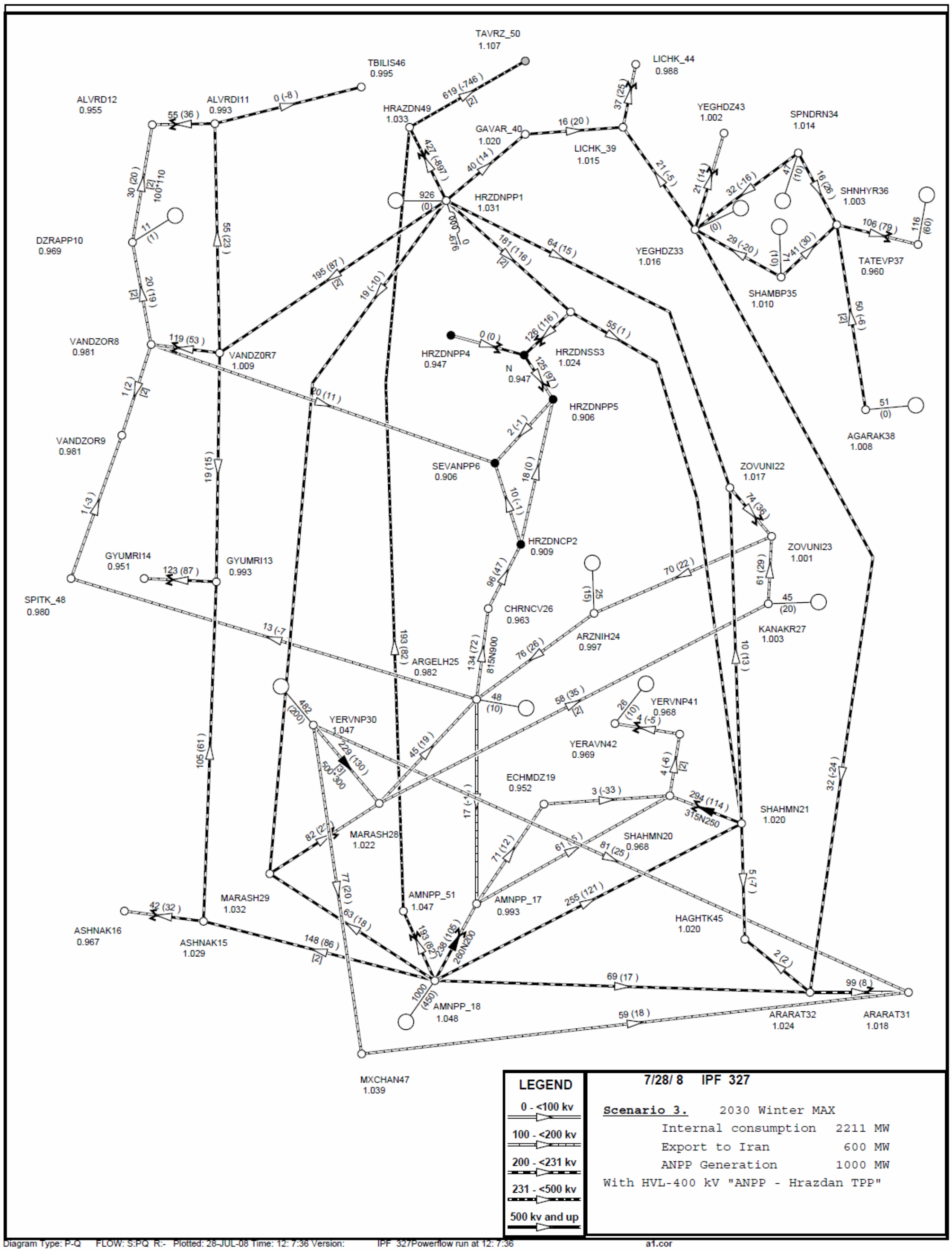


FIG A.3.6.Scenario 3. 2030 Winter max Regime with HVL-400 kV ANPP-Hrazdan TPP

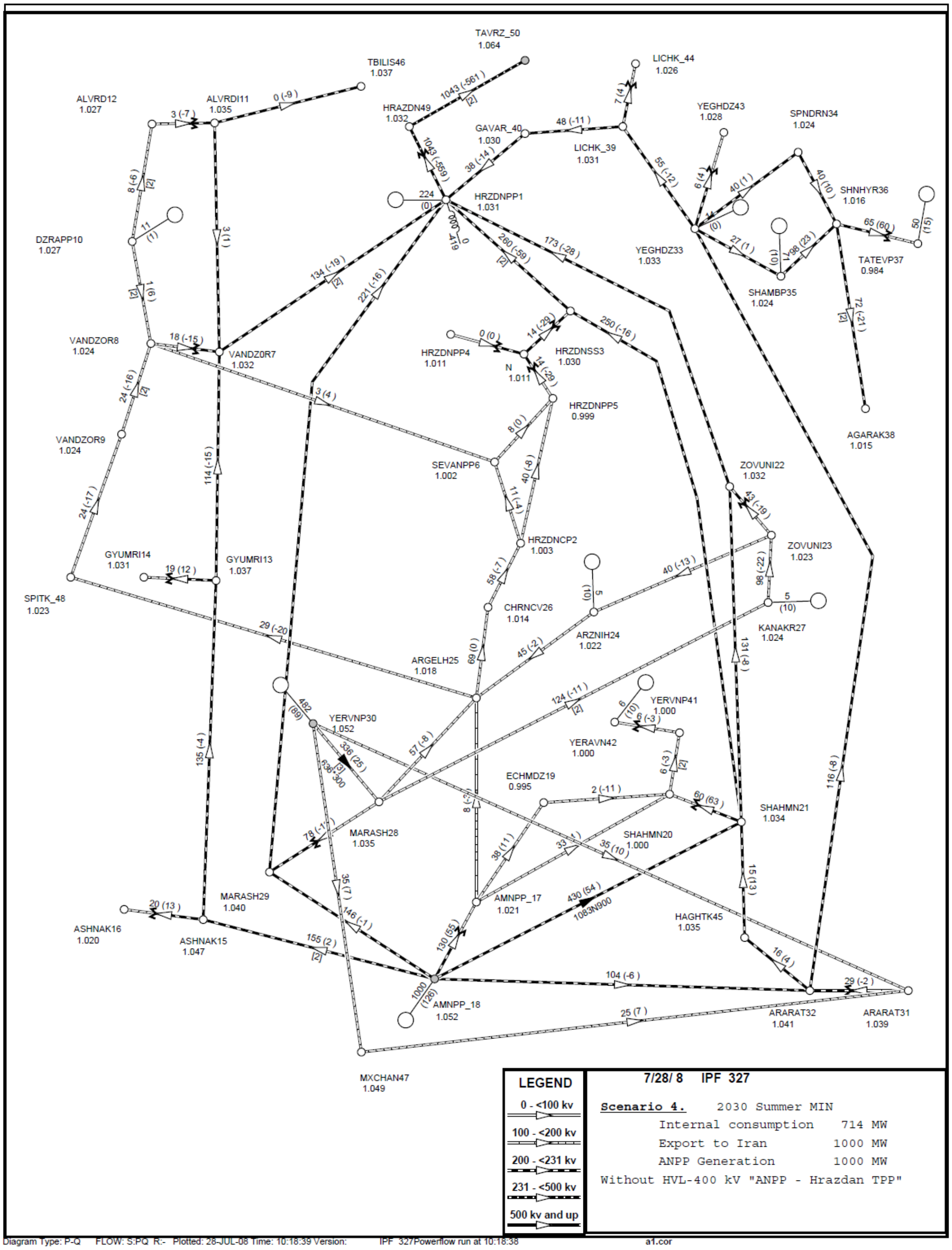


FIG A.3.7.Scenario 4. 2030 Summer min Regime without HVL-400 kV ANPP-Hrazdan TPP

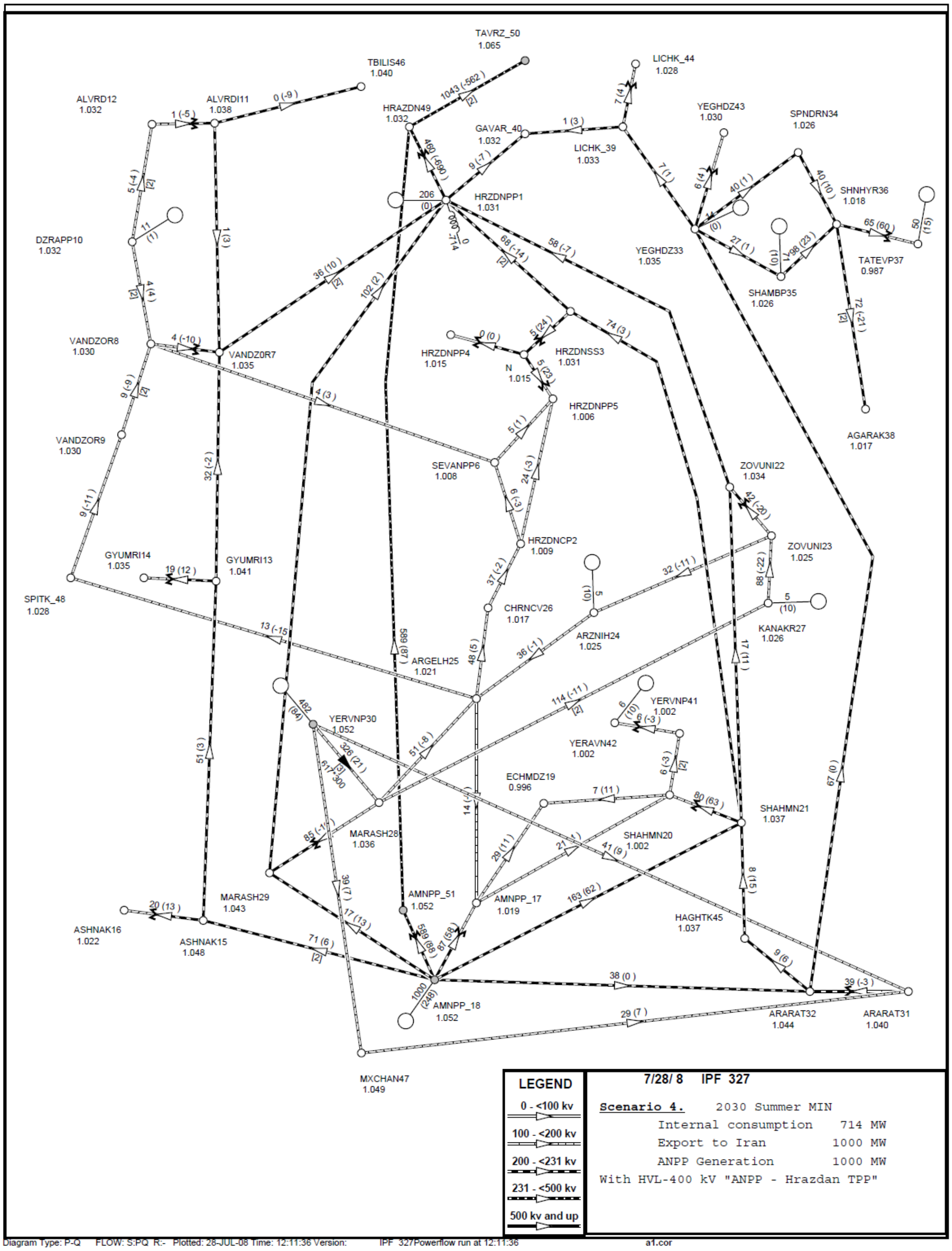


FIG A.3.8.Scenario 4. 2030 Summer min Regime with HVL-400 kV ANPP-Hrazdan TPP

Appendix 4. Transient stability study results

1.2 APPENDIX 4.1.A

```
      Scenario 1.      2017 Winter MAX
                       Short circuit on ANPP's bus-bar with tripping ANPP
                       Disconnection of HVL-400 kV Tabriz
SWING CASE a1         EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  8/ 1/ 8
CASE arm-3        SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3      8  1  1
F1                 1
LS  AMNPP_18 220  ARARAT32 220 1    2    0.0
LS  AMNPP_18 220  ARARAT32 220 1   -2    5.5
LS  AMNPP_18 2201                   4    5.5                          9
LS -HRAZDN49 400 -TAVRZ_50 400 1         11.5
FF      .25 0600.                                    50       0  1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES                                  THE
FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
ECHMDZ19   110.0      0.8554        88.01         5.50
YERAVN42     6.0      0.8611        87.78         5.50
YERVNP41   110.0      0.8614        87.92         5.50
SHAHMN20   110.0      0.8616        88.05         5.50
ASHNAK16   110.0      0.8730        87.86         5.50
HRZDNPP5   110.0      0.8733        90.86         5.50
SEVANPP6   110.0      0.8756        91.29         5.50
HRZDNCP2   110.0      0.8795        91.60         5.50
AMNPP_17   110.0      0.8809        88.19         5.50
GYUMRI14   110.0      0.8871        88.79         5.50
N          220.0      0.8885        90.24         5.50
HRZDNPP4    10.0      0.8885        90.24         5.50
GYUMRI13   220.0      0.9033        88.82         5.50
ASHNAK15   220.0      0.9102        87.91         5.50
ALVRD12    110.0      0.9107        92.48         5.50
SHAHMN21   220.0      0.9110        88.97         5.50
HAGHTK45   220.0      0.9119        89.04         5.50
DZRAPP10   110.0      0.9145        91.94         5.50
VANDZOR8   110.0      0.9146        91.33         5.50
VANDZOR9   110.0      0.9147        91.34         5.50
THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
TAVRZ_50   400.0      1.1475       102.56       148.25
SHAMBP35   220.0      1.1433       107.94       331.25
TATEVP37   110.0      1.1343       109.28        61.50
SPNDRN34   220.0      1.1227       106.03        65.50
SHNHYR36   220.0      1.1212       106.01        63.50
YEGHDZ33   220.0      1.0894       104.31       152.25
YEGHDZ43   110.0      1.0872       105.11       331.25
ARGELH25   110.0      1.0821       108.93       369.25
LICHK_39   220.0      1.0770       104.08       152.25
AGARAK38   220.0      1.0739       101.04        63.50
CHRNCV26   110.0      1.0732       109.11       369.25
GAVAR_40   220.0      1.0724       103.77       150.25
ARZNIH24   110.0      1.0722       107.25       425.25
ZOVUNI23   110.0      1.0663       106.56       427.25
SPITK_48   110.0      1.0658       106.65       425.25
LICHK_44   110.0      1.0657       104.83       152.25
DZRAPP10   110.0      1.0651       107.08       427.25
HRAZDN49   400.0      1.0641       103.03       148.25
KANAKR27   110.0      1.0641       106.37       427.25
HRZDNPP1   220.0      1.0634       103.14       148.25
THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES
```

Scenario 1-a   1

DURING NONFAULT PERIODS.

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
TAVRZ_50	400.0	-2.3514	221.75
HRZDNPP1	220.0	-2.3505	221.75
HRAZDN49	400.0	-2.3504	221.75
TATEVP37	110.0	-2.3493	221.75
HRZDNSS3	220.0	-2.3486	221.75
AGARAK38	220.0	-2.3486	221.75
SHAMBP35	220.0	-2.3484	221.75
SHNHYR36	220.0	-2.3479	221.75
GAVAR_40	220.0	-2.3474	221.75
LICHK_44	110.0	-2.3459	221.75
LICHK_39	220.0	-2.3459	221.75
SPNDRN34	220.0	-2.3444	221.75
YEGHDZ33	220.0	-2.3432	221.75
YEGHDZ43	110.0	-2.3432	221.75
AMNPP_51	400.0	-2.3431	221.75
AMNPP_18	220.0	-2.3428	221.75
ASHNAK16	110.0	-2.3427	221.75
ASHNAK15	220.0	-2.3424	221.75
GYUMRI14	110.0	-2.3415	221.75
GYUMRI13	220.0	-2.3412	221.75

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
YEGHDZ33	220.0		2.8746	241.25
TATEVP37	110.0	1	2.3843	214.50
SHAMBP35	220.0	1	2.3719	221.75
HRZDNPP1	220.0	1	2.3633	221.75
AGARAK38	220.0	1	2.3512	223.00
SPNDRN34	220.0	1	2.3495	198.25
KANAKR27	110.0	1	2.3470	227.25
ARZNIH24	110.0	1	2.3324	229.25
TBILIS46	220.0	1	2.3178	235.25
DZRAPP10	110.0	1	2.3011	223.00
YERVNP30	110.0	1	2.3009	261.25
ARGELH25	110.0	1	2.2918	223.75
SEVANPP6	110.0	1	2.2834	208.25
YERAVN42	6.0	1	2.2703	231.25
AMNPP_18	220.0	1	0.0215	2.00

The following 20 generators have the highest field voltage deviations

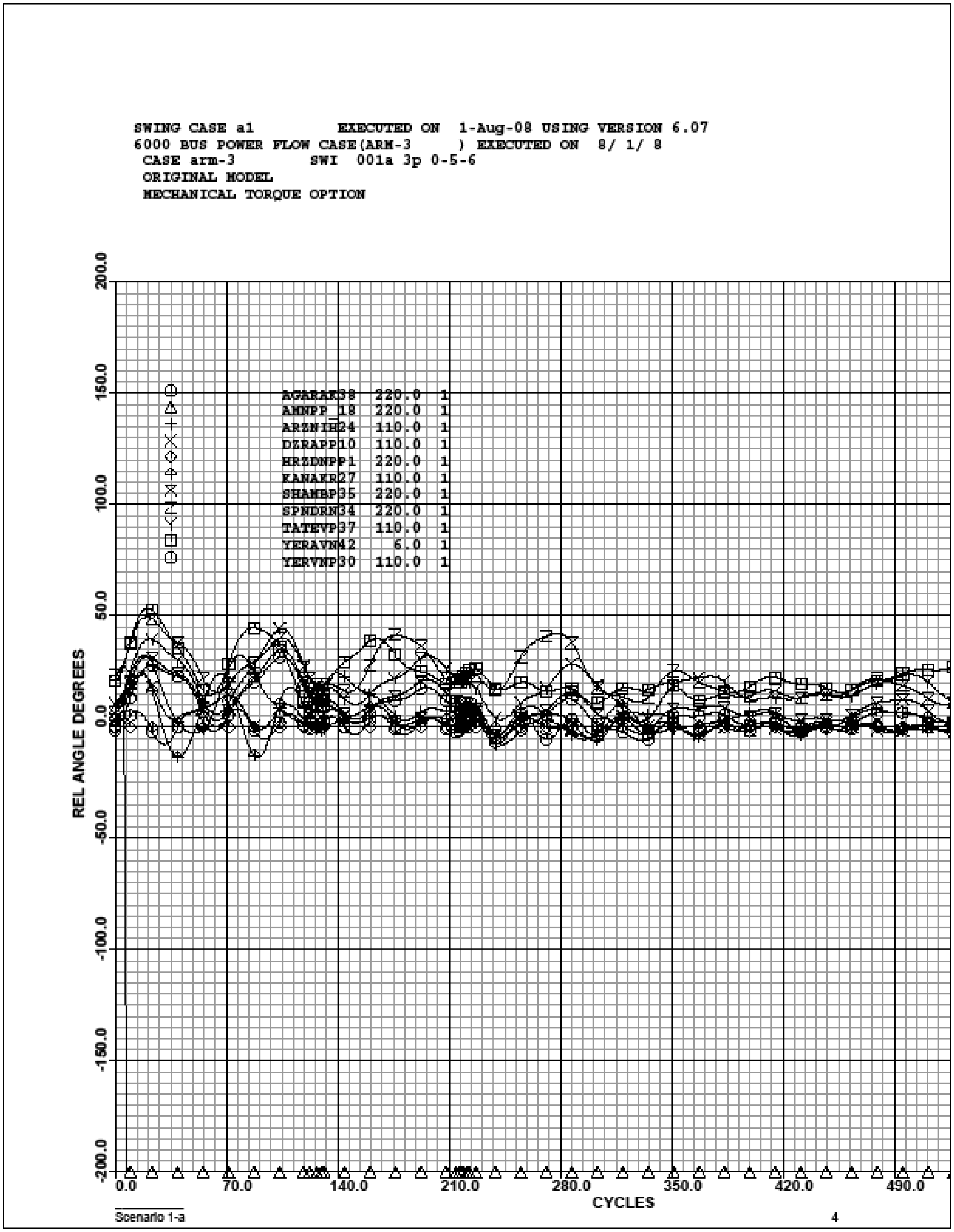
GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
AMNPP_18	220.0	1	3.0621	2.00
SEVANPP6	110.0	1	2.2017	425.25
ARGELH25	110.0	1	2.1979	369.25
SHAMBP35	220.0	1	2.1817	331.25
DZRAPP10	110.0	1	2.0597	427.25
KANAKR27	110.0	1	1.9065	427.25
TATEVP37	110.0	1	1.8823	61.50
SPNDRN34	220.0	1	1.8708	65.50
ARZNIH24	110.0	1	1.7942	425.25
YERAVN42	6.0	1	1.5345	5.50
HRZDNPP1	220.0	1	0.5620	53.50
YERVNP30	110.0	1	0.2041	17.50
AGARAK38	220.0	1	0.0727	85.50

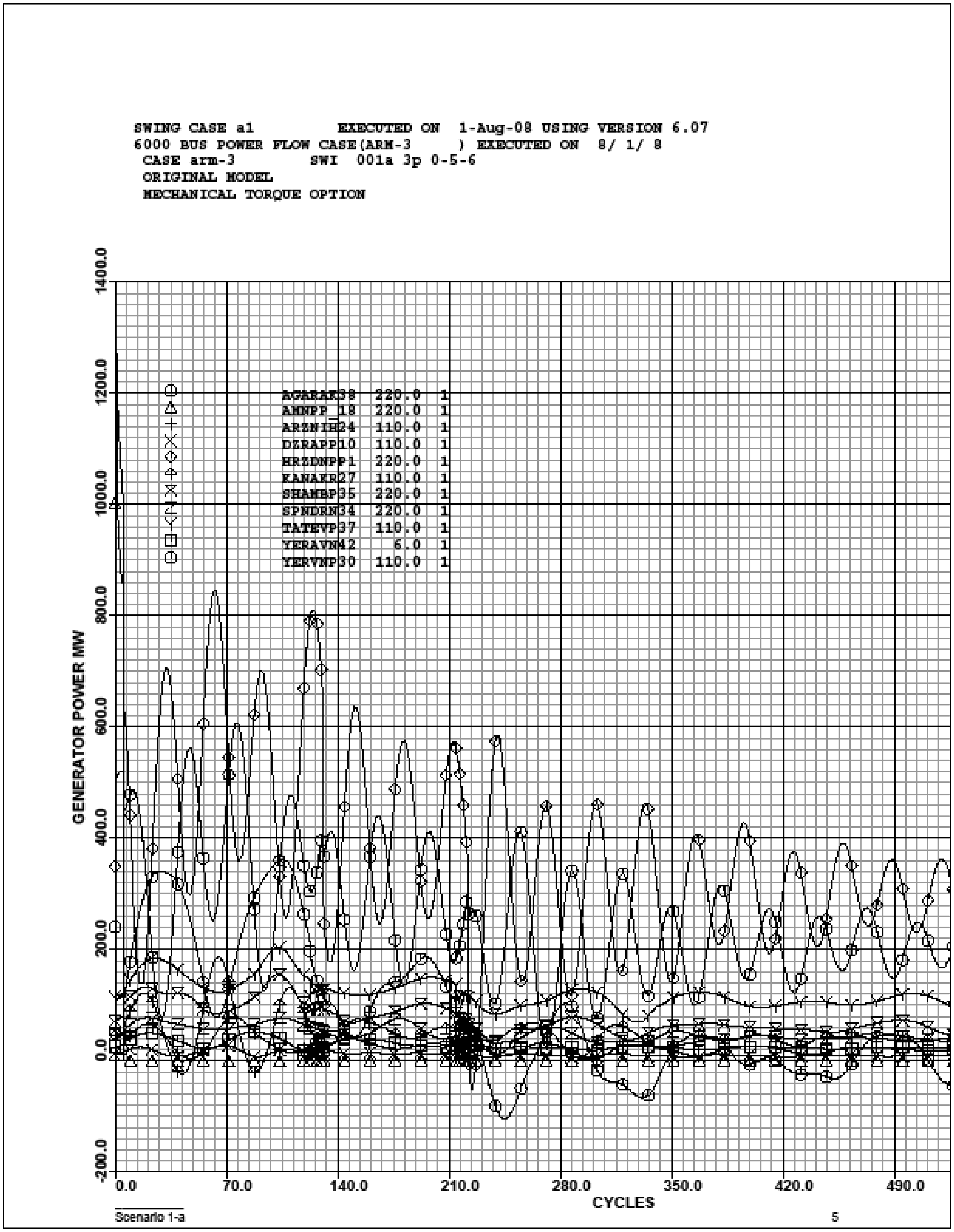
THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

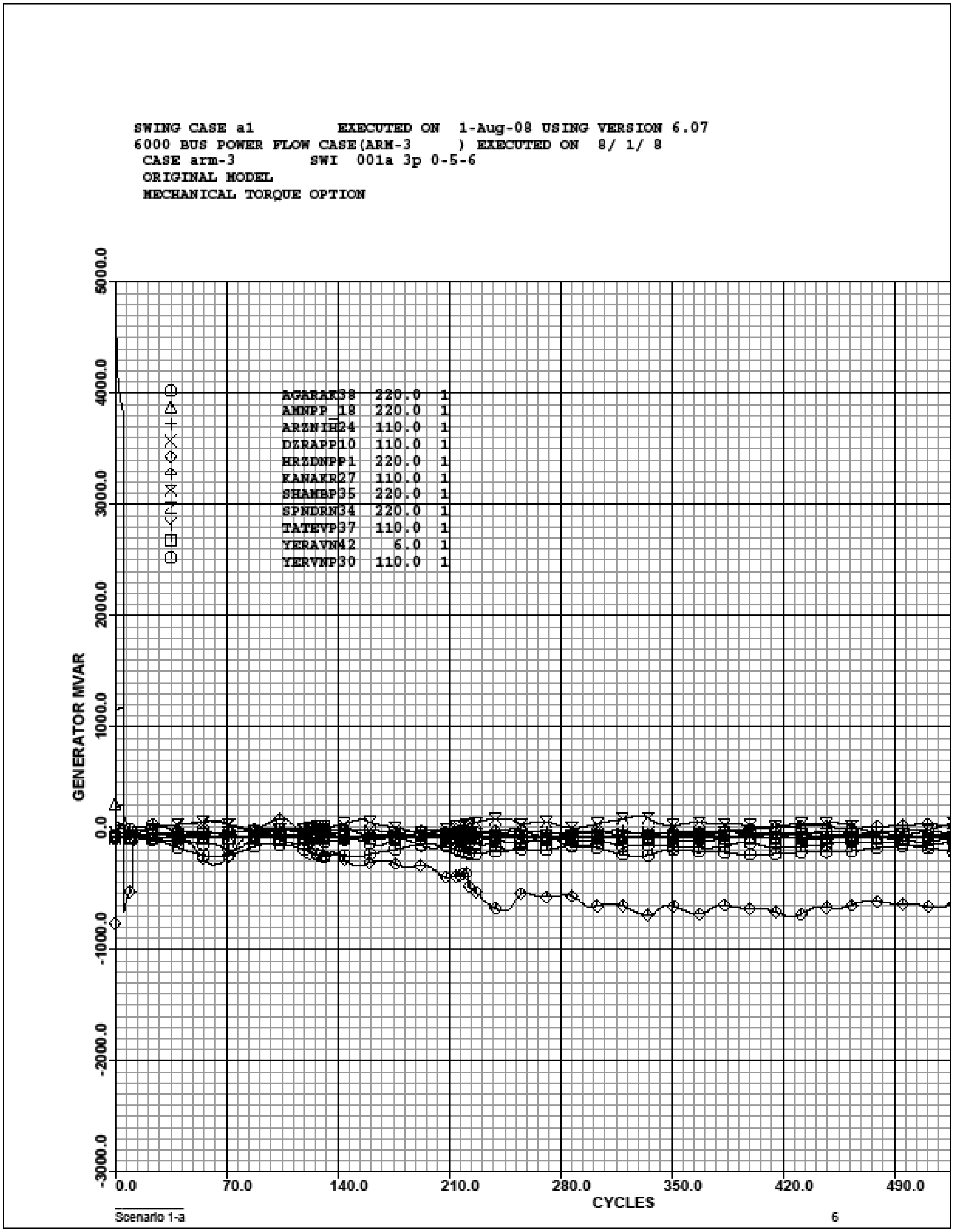
GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
ARGELH25	110.0	1	0.0500	25.50
DZRAPP10	110.0	1	0.0500	31.50
KANAKR27	110.0	1	0.0500	31.50
ARZNIH24	110.0	1	0.0500	35.50
YERAVN42	6.0	1	0.0500	47.50
SEVANPP6	110.0	1	0.0500	117.50
TATEVP37	110.0	1	0.0500	123.50
SHAMBP35	220.0	1	0.0500	142.25

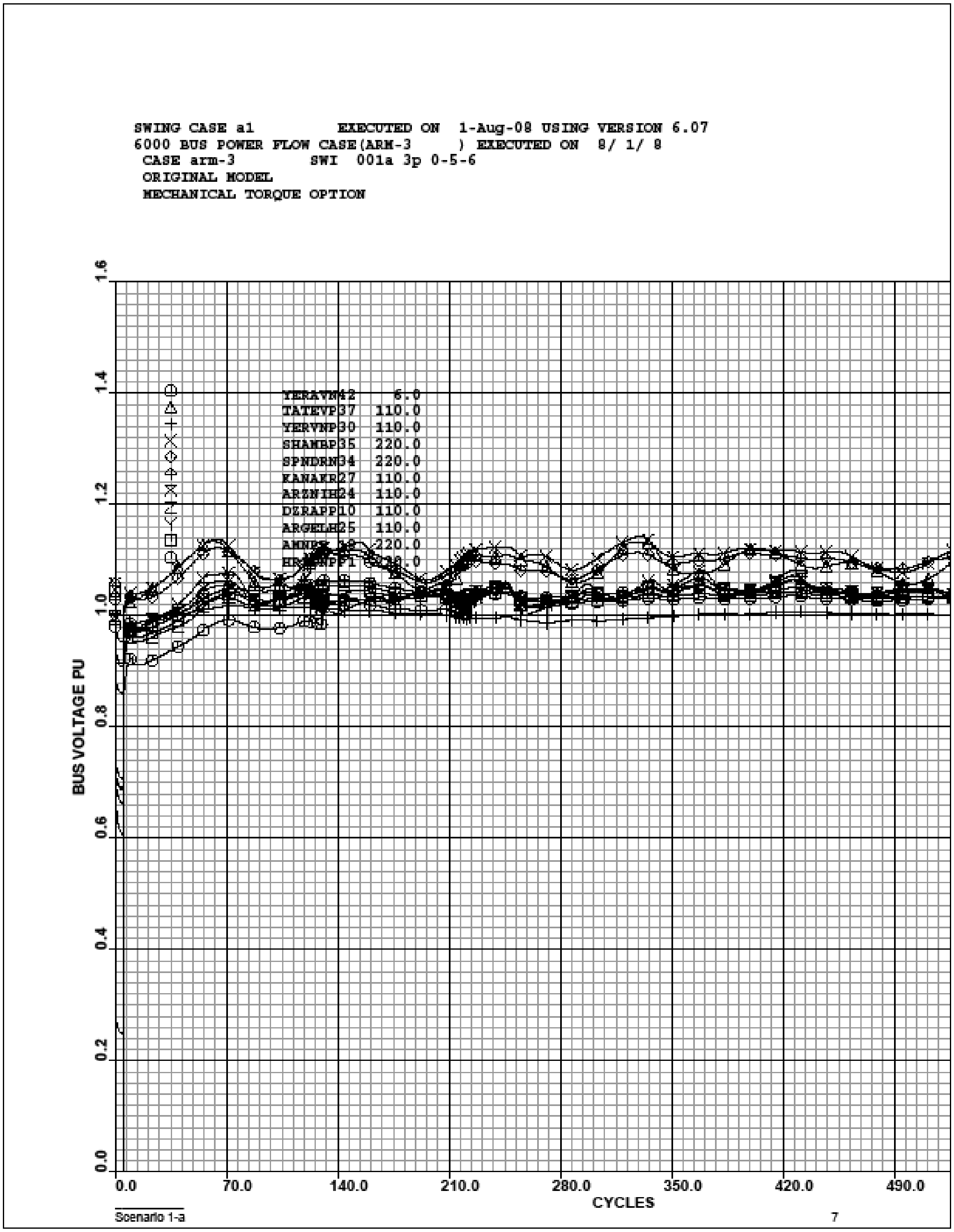
```
*********************************************************************
****                                                            ****
****                          VFHIST                            ****
****                                                            ****
****      GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT      ****
****                                                            ****
****          TIME INTERVAL =     0.0 TO   597.2 CYCLES         ****
****                                                            ****
****                                                            ****
**** BASE CASE TITLE:                                           ****
**** ARM-3                                                      ****
**** a1                                                         ****
****                                                            ****
*********************************************************************
------ No-load bus relative voltage dip below     0.0% For entire system -----
-        Bus  name          start    end   elapsed    VLO%     area
cycles  cycles  cycles
[AMNPP_51 400.0]  172.25  600.00  427.75   98.09   1 System
[HRAZDN49 400.0]  445.25  600.00  154.75   99.53   1 System
[HRZDNPP1 220.0]  455.25  600.00  144.75   99.60   1 System
[AMNPP_51 400.0]    5.50  130.75  125.25   87.63   1 System
[ASHNAK15 220.0]    5.50  130.75  125.25   87.92   1 System
[HRAZDN49 400.0]  255.25  335.25   80.00   99.09   1 System
[ASHNAK15 220.0]  523.25  600.00   76.75   99.63   1 System
[HRZDNPP1 220.0]  255.25  331.25   76.00   99.17   1 System
[MARASH29 220.0]  255.25  327.25   72.00   98.93   1 System
[ASHNAK15 220.0]  253.25  325.25   72.00   99.09   1 System
[TBILIS46 220.0]  251.25  309.25   58.00   99.39   1 System
[HRZDNSS3 220.0]  259.25  317.25   58.00   99.57   1 System
[GYUMRI13 220.0]    5.50   63.50   58.00   88.82   1 System
[ALVRDI11 220.0]    5.50   59.50   54.00   93.47   1 System
[SHAHMN21 220.0]    5.50   57.50   52.00   88.98   1 System
[YERVNP41 110.0]    5.50   57.50   52.00   87.92   1 System
[VANDZOR7 220.0]    5.50   55.50   50.00   90.33   1 System
[HRZDNPP1 220.0]    5.50   55.50   50.00   89.10   1 System
[HRAZDN49 400.0]    5.50   55.50   50.00   89.08   1 System
[ARARAT32 220.0]    5.50   53.50   48.00   90.68   1 System
------ Load bus relative voltage dip below     0.0% for entire system -------
Bus  name           start    end   elapsed    vlo%     area
cycles  cycles  cycles
[AMNPP_18 220.0]  172.25  600.00  427.75   98.04   1 System
[YERVNP30 110.0]  210.00  357.25  147.25   98.69   1 System
[MXCHAN47 110.0]  210.00  351.25  141.25   98.80   1 System
[TAVRZ_50 400.0]    5.50  131.00  125.50   88.76   1 System
[AMNPP_18 220.0]    5.50  130.75  125.25   87.59   1 System
[ASHNAK16 110.0]    5.50  130.75  125.25   87.86   1 System
[AGARAK38 220.0]  419.25  519.25  100.00   99.63   1 System
[YERVNP30 110.0]  525.25  600.00   74.75   99.72   1 System
[AGARAK38 220.0]  160.25  223.75   63.50   99.33   1 System
[MXCHAN47 110.0]  537.25  600.00   62.75   99.77   1 System
[GYUMRI14 110.0]    5.50   63.50   58.00   88.79   1 System
[ARARAT31 110.0]  255.25  313.25   58.00   98.99   1 System
[AMNPP_17 110.0]    5.50   57.50   52.00   88.19   1 System
[YERAVN42   6.0]    5.50   57.50   52.00   87.78   1 System
[HAGHTK45 220.0]    5.50   57.50   52.00   89.04   1 System
[SHAHMN20 110.0]    5.50   57.50   52.00   88.05   1 System
[ECHMDZ19 110.0]    5.50   57.50   52.00   88.01   1 System
[GAVAR_40 220.0]    5.50   51.50   46.00   90.41   1 System
[ARARAT31 110.0]    5.50   49.50   44.00   94.81   1 System
[VANDZOR9 110.0]    5.50   49.50   44.00   91.34   1 System
```

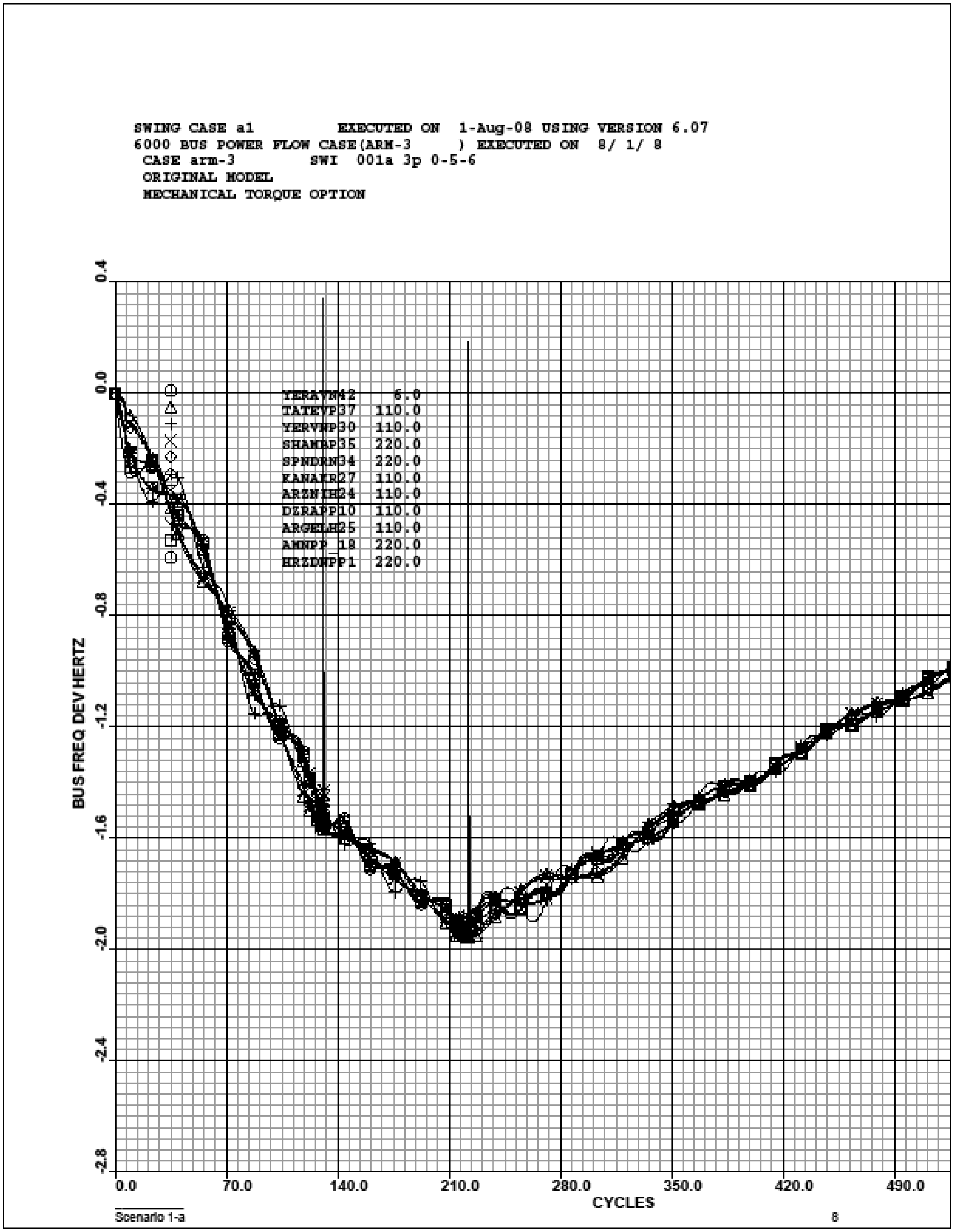
Scenario 1-a   3


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP 18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
200.0
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-a
4


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR POWER MW
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-a
5


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
-2000.0
-3000.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-a
6


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
SHAMBP35 220.0
SPNDRN34 220.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
ARGELH25 110.0
BUS VOLTAGE PU
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-a
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
SHAMBP35 220.0
SPNDRN34 220.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
ARGELH25 110.0
AMNPP_18 220.0
HRZDNPP1 220.0
BUS FREQ DEV HERTZ
0.4
0.0
-0.4
-0.8
-1.2
-1.6
-2.0
-2.4
-2.8
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-a
8

1.3 APPENDIX 4.1.B

Scenario 1. 2017 Winter MAX
Short circuit on bus-bar of HVL-400 kV Tabriz with tripping HVL
Disconnection of ANPP

```
  SWING CASE a1         EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  8/ 1/ 8
CASE arm-3        SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3      8  1  1
F1                    1
LS  HRAZDN49 400  TAVRZ_50 400 1    2    0.0
LS -HRAZDN49 400 -TAVRZ_50 400 1   -2    5.5
LS  AMNPP_18 2201                   4    11.5                            9
FF      .25 0600.                                   50      0  1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES                                   THE
FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
```

BUS NAME	BASE KV	VOLTAGE(PU)	RELATIVE %	TIME(CYCLES)
HRZDNPP1	220.0	0.8196	79.49	5.50
HRZDNPP5	110.0	0.8212	85.44	5.50
HRAZDN49	400.0	0.8220	79.59	5.50
N	220.0	0.8225	83.54	5.50
HRZDNPP4	10.0	0.8225	83.54	5.50
HRZDNSS3	220.0	0.8269	80.50	5.50
SEVANPP6	110.0	0.8271	86.24	5.50
HRZDNCP2	110.0	0.8358	87.04	5.50
TAVRZ_50	400.0	0.8408	75.14	5.50
VANDZOR7	220.0	0.8519	83.49	5.50
ECHMDZ19	110.0	0.8527	87.73	5.50
SHAHMN20	110.0	0.8541	87.28	5.50
YERVNP41	110.0	0.8551	87.27	5.50
YERAVN42	6.0	0.8560	87.25	5.50
ALVRD12	110.0	0.8595	87.28	5.50
VANDZOR8	110.0	0.8609	85.96	5.50
VANDZOR9	110.0	0.8613	86.00	5.50
DZRAPP10	110.0	0.8614	86.60	5.50
GYUMRI14	110.0	0.8637	86.45	5.50
GAVAR_40	220.0	0.8652	83.71	5.50

THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES

BUS NAME	BASE KV	VOLTAGE(PU)	RELATIVE %	TIME(CYCLES)
TAVRZ_50	400.0	1.1593	103.61	151.25
SHAMBP35	220.0	1.1472	108.30	337.50
TATEVP37	110.0	1.1377	109.61	331.50
SHNHYR36	220.0	1.1237	106.25	337.50
SPNDRN34	220.0	1.1186	105.64	75.50
YEGHDZ33	220.0	1.0945	104.79	159.25
YEGHDZ43	110.0	1.0903	105.41	339.50
LICHK_39	220.0	1.0839	104.75	157.25
ARGELH25	110.0	1.0822	108.93	377.50
GAVAR_40	220.0	1.0804	104.54	157.25
HRAZDN49	400.0	1.0746	104.04	151.25
HRZDNPP1	220.0	1.0738	104.15	147.25
CHRNCV26	110.0	1.0735	109.15	377.50
AGARAK38	220.0	1.0729	100.95	69.50
LICHK_44	110.0	1.0726	105.51	157.25
HRZDNSS3	220.0	1.0704	104.20	153.25
ARZNIH24	110.0	1.0697	107.00	377.50
ARARAT32	220.0	1.0668	103.48	159.25
AMNPP_51	400.0	1.0657	101.99	155.25
AMNPP_18	220.0	1.0652	101.93	155.25

THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES

Scenario 1-b 1

DURING NONFAULT PERIODS.

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
AGARAK38	220.0	-2.3533	232.00
TATEVP37	110.0	-2.3518	231.00
SHNHYR36	220.0	-2.3461	231.00
SHAMBP35	220.0	-2.3447	231.00
SPNDRN34	220.0	-2.3372	231.00
YEGHDZ33	220.0	-2.3271	231.00
YEGHDZ43	110.0	-2.3270	231.00
LICHK_39	220.0	-2.3192	231.00
LICHK_44	110.0	-2.3191	231.00
YERVNP30	110.0	-2.3180	233.25
MXCHAN47	110.0	-2.3163	232.00
GAVAR_40	220.0	-2.3151	231.00
ARARAT32	220.0	-2.3149	231.00
ARARAT31	110.0	-2.3143	231.00
MARASH28	110.0	-2.3112	232.00
MARASH29	220.0	-2.3092	231.00
HAGHTK45	220.0	-2.3090	231.00
SHAHMN21	220.0	-2.3087	231.00
AMNPP_18	220.0	-2.3085	231.00
AMNPP_51	400.0	-2.3085	231.00

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
YEGHDZ33	220.0		2.7980	245.50
SPNDRN34	220.0	1	2.4070	207.25
TATEVP37	110.0	1	2.4056	232.25
SHAMBP35	220.0	1	2.3778	230.00
AGARAK38	220.0	1	2.3570	233.25
KANAKR27	110.0	1	2.3570	243.50
ARGELH25	110.0	1	2.3354	237.00
YERVNP30	110.0	1	2.3244	233.50
ARZNIH24	110.0	1	2.3241	243.50
SEVANPP6	110.0	1	2.3082	228.00
HRZDNPP1	220.0	1	2.3079	231.00
DZRAPP10	110.0	1	2.3027	233.50
TBILIS46	220.0	1	2.2966	241.50
YERAVN42	6.0	1	2.2852	205.25
AMNPP_18	220.0	1	0.2148	11.50

The following 20 generators have the highest field voltage deviations

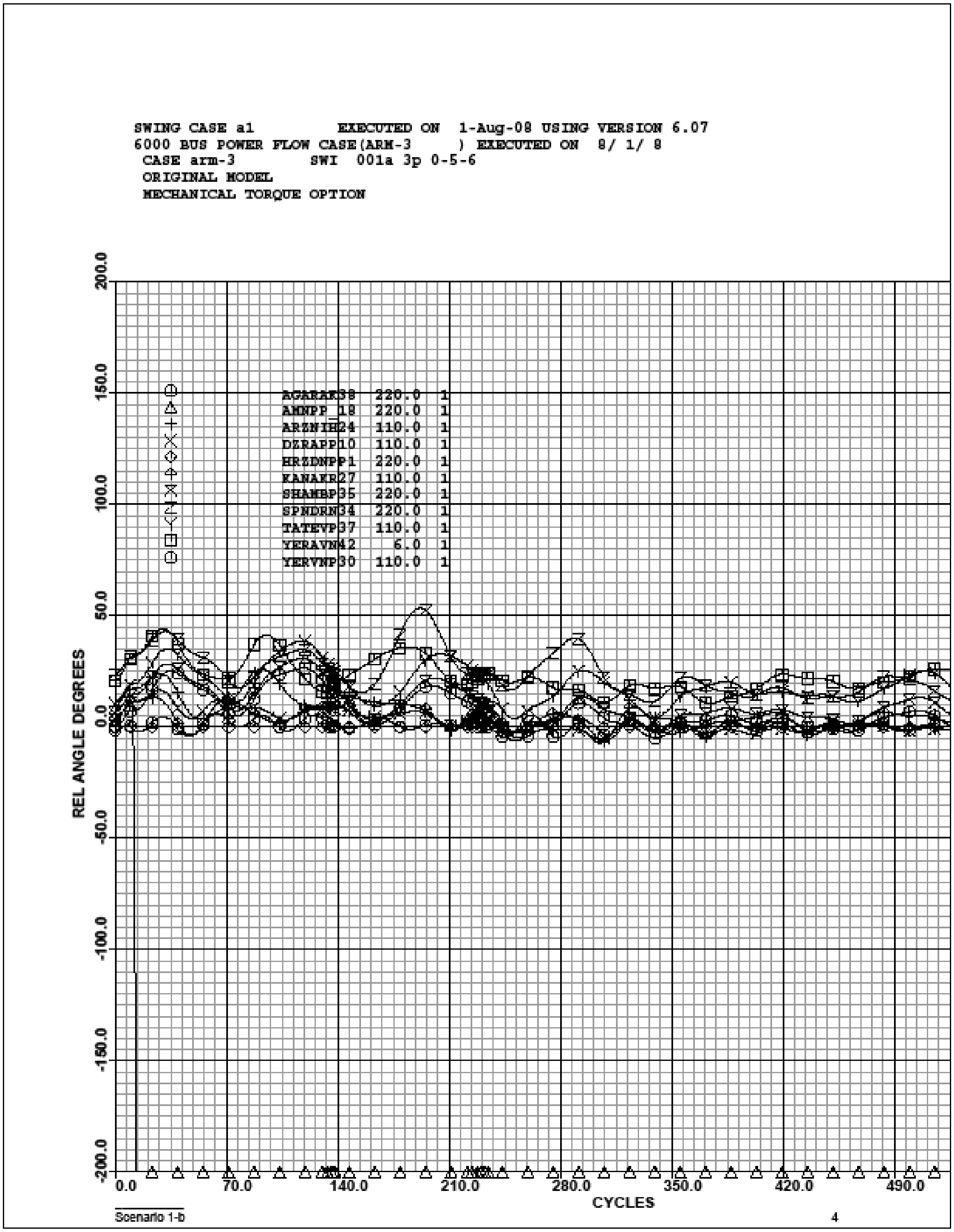
GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
AMNPP_18	220.0	1	3.0621	2.00
SEVANPP6	110.0	1	2.2009	377.50
ARGELH25	110.0	1	2.1982	377.50
SHAMBP35	220.0	1	2.1937	337.50
DZRAPP10	110.0	1	2.0516	435.50
KANAKR27	110.0	1	1.8959	435.50
TATEVP37	110.0	1	1.8928	331.50
SPNDRN34	220.0	1	1.8582	75.50
ARZNIH24	110.0	1	1.7865	377.50
YERAVN42	6.0	1	0.9630	377.50
HRZDNPP1	220.0	1	0.7432	53.50
YERVNP30	110.0	1	0.1904	19.50
AGARAK38	220.0	1	0.0731	95.50

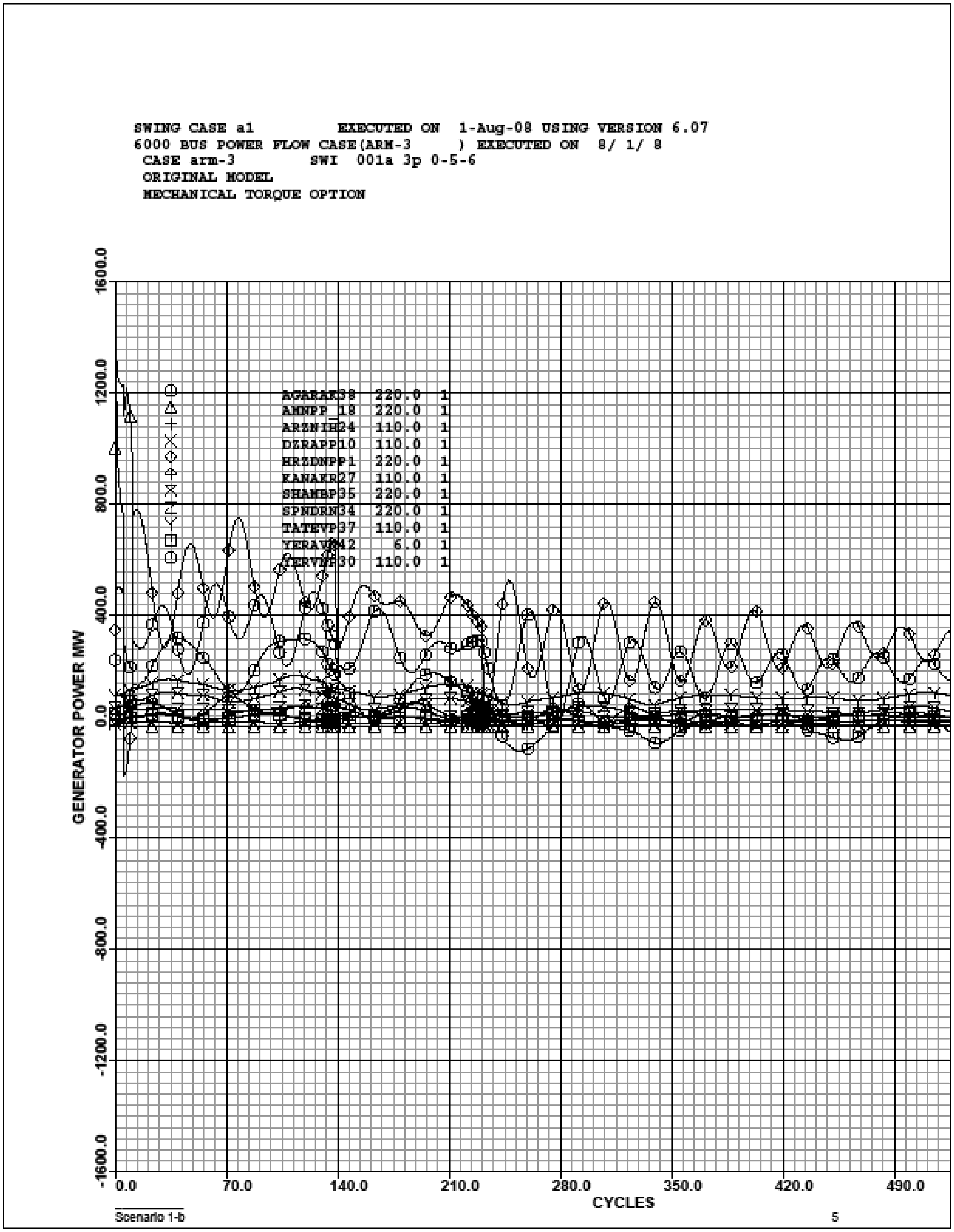
THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

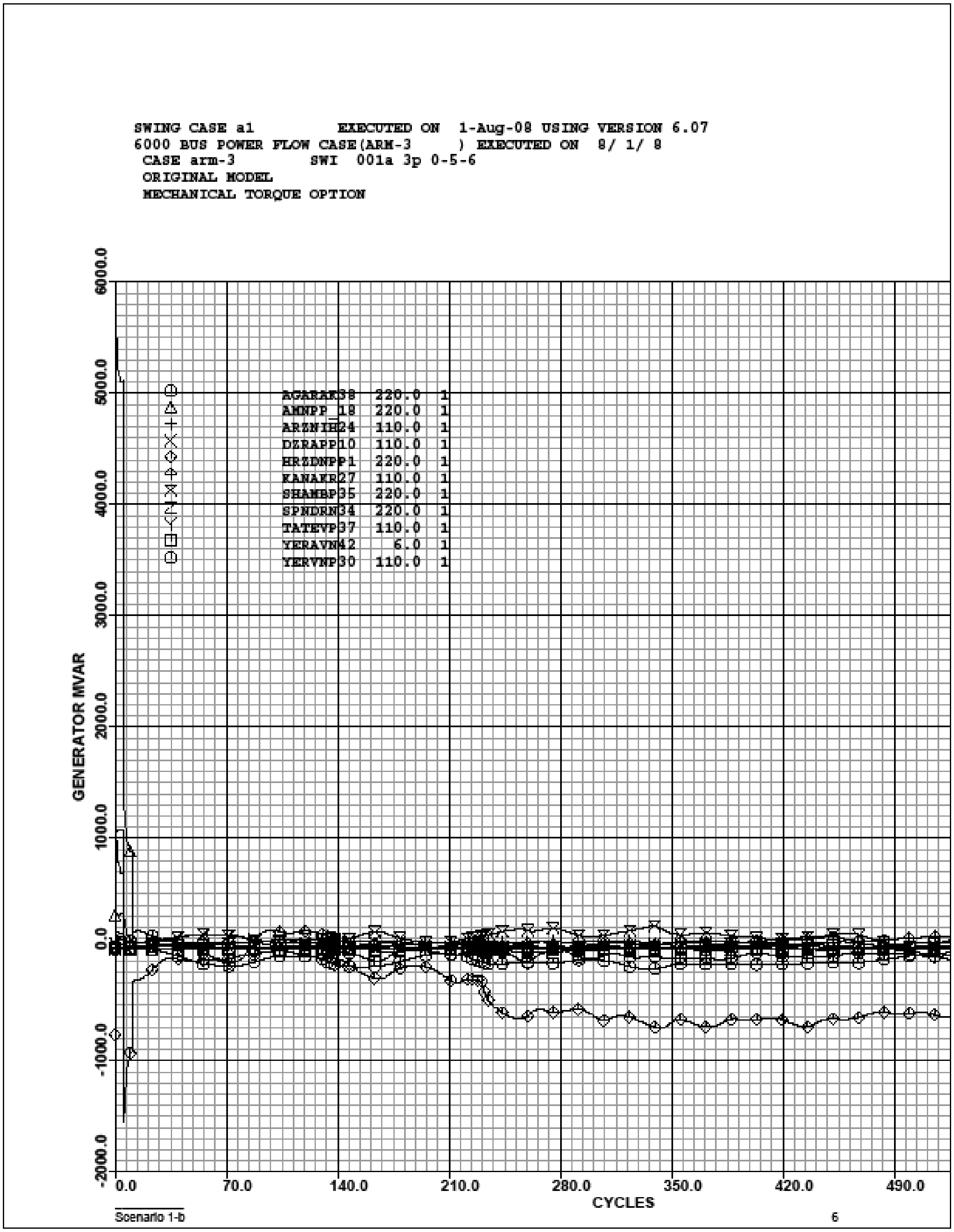
GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
KANAKR27	110.0	1	0.0500	39.50
DZRAPP10	110.0	1	0.0500	41.50
ARZNIH24	110.0	1	0.0500	51.50
YERAVN42	6.0	1	0.0500	119.50
TATEVP37	110.0	1	0.0500	134.75
SHAMBP35	220.0	1	0.0500	149.25
ARGELH25	110.0	1	0.0500	157.25
SEVANPP6	110.0	1	0.0500	234.00

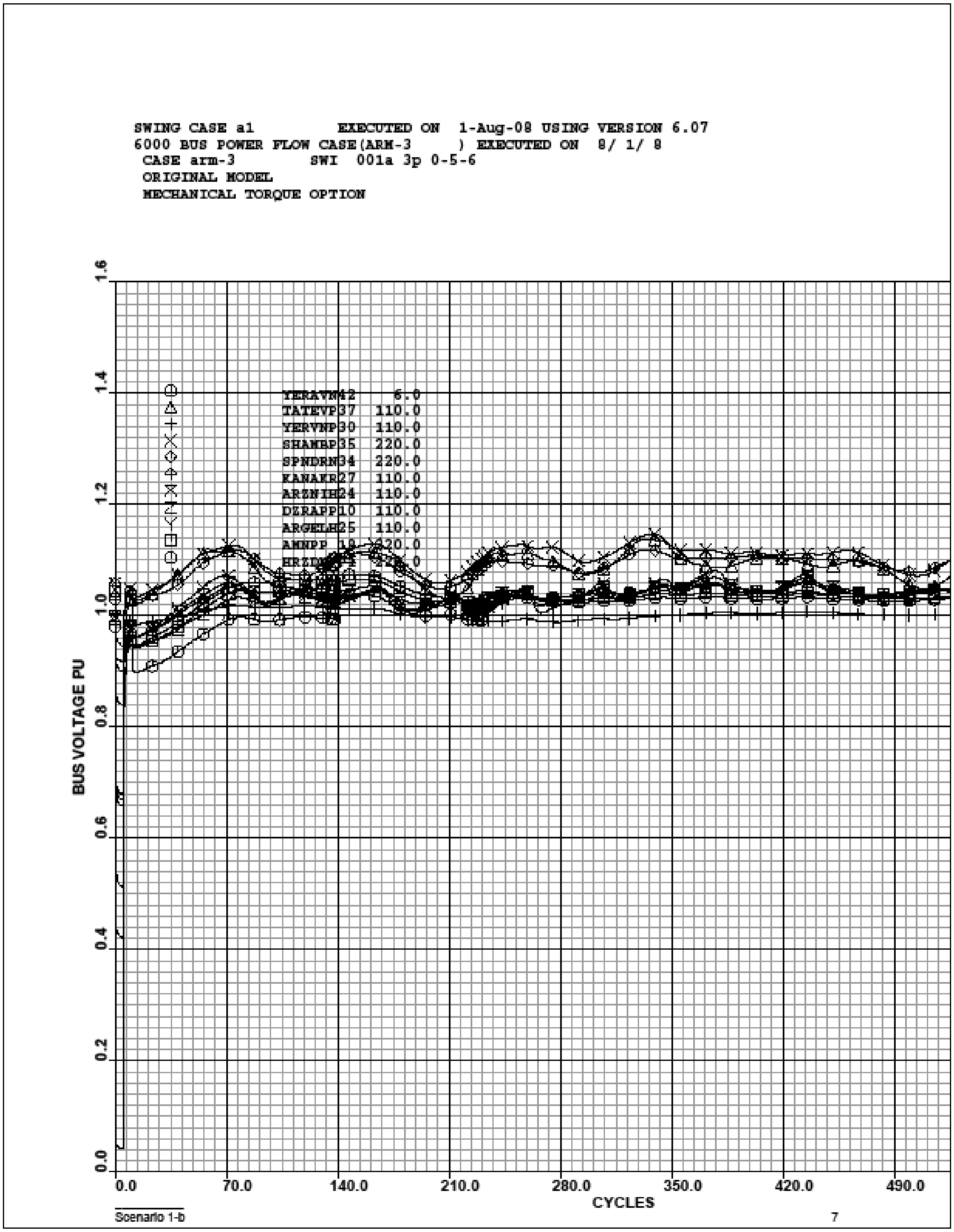
```
*******************************************************************
****                                                          ****
****                          VFHIST                          ****
****                                                          ****
****      GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT    ****
****                                                          ****
****           TIME INTERVAL =     0.0 TO   597.5 CYCLES      ****
****                                                          ****
****                                                          ****
**** BASE CASE TITLE:                                         ****
**** ARM-3                                                    ****
**** a1                                                       ****
****                                                          ****
*******************************************************************
------ No-load bus relative voltage dip below     0.0% For entire system -----
-        Bus  name            start    end   elapsed    VLO%     area
cycles  cycles  cycles
[AMNPP_51 400.0]  181.25  600.00  418.75   97.39   1 System
[HRAZDN49 400.0]  445.50  600.00  154.50   99.51   1 System
[HRZDNPP1 220.0]  449.50  523.50   74.00   99.59   1 System
[HRAZDN49 400.0]  261.50  335.50   74.00   99.23   1 System
[HRZDNPP1 220.0]  263.50  333.50   70.00   99.31   1 System
[AMNPP_51 400.0]    5.50   75.50   70.00   89.02   1 System
[ASHNAK15 220.0]    5.50   73.50   68.00   88.61   1 System
[ASHNAK15 220.0]  535.50  600.00   64.50   99.77   1 System
[ALVRDI11 220.0]    5.50   69.50   64.00   88.94   1 System
[ASHNAK15 220.0]  263.50  327.50   64.00   99.27   1 System
[HRZDNPP1 220.0]  537.50  600.00   62.50   99.91   1 System
[MARASH29 220.0]  263.50  325.50   62.00   99.17   1 System
[GYUMRI13 220.0]    5.50   67.50   62.00   86.49   1 System
[ASHNAK15 220.0]  461.50  521.50   60.00   99.58   1 System
[VANDZOR7 220.0]    5.50   63.50   58.00   83.50   1 System
[TBILIS46 220.0]  263.50  321.50   58.00   99.70   1 System
[YERVNP41 110.0]    5.50   63.50   58.00   87.27   1 System
[ASHNAK15 220.0]  185.25  241.50   56.25   97.98   1 System
[MARASH29 220.0]  193.25  249.50   56.25   98.78   1 System
[SHAHMN21 220.0]    5.50   61.50   56.00   86.69   1 System
------ Load bus relative voltage dip below     0.0% for entire system -------
Bus  name            start    end   elapsed    vlo%     area
cycles  cycles  cycles
[AMNPP_18 220.0]  179.25  600.00  420.75   97.34   1 System
[YERVNP30 110.0]  185.25  345.50  160.25   98.79   1 System
[AGARAK38 220.0]  369.50  525.50  156.00   99.65   1 System
[MXCHAN47 110.0]  185.25  335.50  150.25   98.94   1 System
[TAVRZ_50 400.0]    5.50  138.50  133.00   75.14   1 System
[YERVNP30 110.0]  525.50  600.00   74.50   99.75   1 System
[AMNPP_18 220.0]    5.50   75.50   70.00   89.39   1 System
[ASHNAK16 110.0]    5.50   73.50   68.00   88.56   1 System
[GYUMRI14 110.0]    5.50   67.50   62.00   86.45   1 System
[AGARAK38 220.0]  171.25  232.50   61.25   99.31   1 System
[ARARAT31 110.0]  187.25  247.50   60.25   99.06   1 System
[MXCHAN47 110.0]  541.50  600.00   58.50   99.82   1 System
[SHAHMN20 110.0]    5.50   63.50   58.00   87.28   1 System
[AMNPP_17 110.0]    5.50   63.50   58.00   88.86   1 System
[ECHMDZ19 110.0]    5.50   63.50   58.00   87.73   1 System
[YERAVN42   6.0]    5.50   61.50   56.00   87.25   1 System
[HAGHTK45 220.0]    5.50   61.50   56.00   86.80   1 System
[ARARAT31 110.0]  265.50  317.50   52.00   99.28   1 System
[GAVAR_40 220.0]    5.50   55.50   50.00   83.71   1 System
[LICHK_44 110.0]    5.50   55.50   50.00   86.00   1 System
```

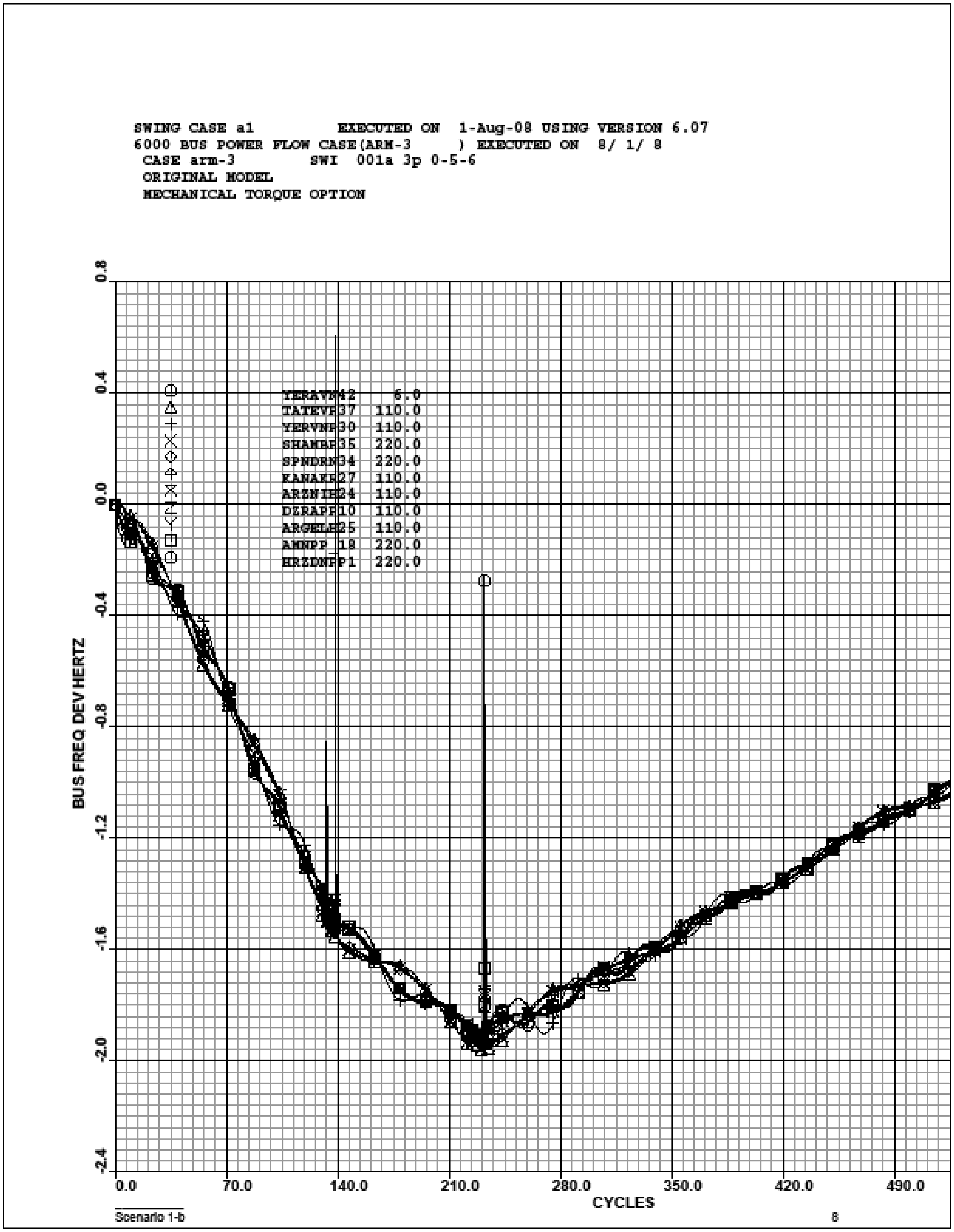
Scenario 1-b   3


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
200.0
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-b
4


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNT30 110.0 1
GENERATOR POWER MW
1600.0
1200.0
800.0
400.0
0.0
-400.0
-800.0
-1200.0
-1600.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-b
5


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
-2000.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-b
6


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
SHAMBP35 220.0
SPNDRN34 220.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
ARGELH25 110.0
AMNPP
BUS VOLTAGE PU
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-b
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
SHAMBP35 220.0
SPNDRN34 220.0
KANAKR27 110.0
ARZNIB24 110.0
DZRAPP10 110.0
ARGELB25 110.0
AMNPP_18 220.0
HRZDNPP1 220.0
BUS FREQ DEV HERTZ
0.8
0.4
0.0
-0.4
-0.8
-1.2
-1.6
-2.0
-2.4
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 1-b
8

1.4 APPENDIX 4.2.A

```
    Scenario 2.        2017 Summer MIN
                       Short circuit on ANPP's bus-bar with tripping ANPP
                       Disconnection of HVL-400 kV Tabriz

SWING CASE a1        EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  7/31/ 8
CASE arm-3       SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3      8  1  1
F1                   1
LS  AMNPP_18 220  ARARAT32 220 1    2    0.0
LS  AMNPP_18 220  ARARAT32 220 1   -2    5.5
LS  AMNPP_18 2201                   4    5.5                          9
LS -HRAZDN49 400 -TAVRZ_50 400 1         11.5
FF      .25 0600.                                  50       0   1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES
THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
ECHMDZ19   110.0      0.9018        89.08          5.50
SHAHMN20   110.0      0.9064        89.14          5.50
YERAVN42     6.0      0.9064        89.05          5.50
YERVNP41   110.0      0.9064        89.10          5.50
ASHNAK16   110.0      0.9138        88.62          5.50
AMNPP_17   110.0      0.9163        89.06          5.50
HRZDNPP1   220.0      0.9198        89.21          5.50
HRAZDN49   400.0      0.9212        89.20          5.50
HRZDNSS3   220.0      0.9216        89.35          5.50
N          220.0      0.9260        90.61          5.50
HRZDNPP4    10.0      0.9261        90.62          5.50
HRZDNPP5   110.0      0.9283        91.32          5.50
AMNPP_51   400.0      0.9294        88.38          5.50
AMNPP_18   220.0      0.9296        88.36          5.50
GYUMRI14   110.0      0.9297        89.38          5.50
SHAHMN21   220.0      0.9299        89.57          5.50
ASHNAK15   220.0      0.9303        88.63          5.50
HAGHTK45   220.0      0.9306        89.64          5.50
TAVRZ_50   400.0      0.9324        85.30         13.50
GYUMRI13   220.0      0.9334        89.38          5.50
THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
N          220.0      2.7768       271.70        600.00
HRZDNPP4    10.0      2.7753       271.55        600.00
HRZDNPP5   110.0      2.3897       235.10        600.00
SEVANPP6   110.0      2.2339       219.36        600.00
HRZDNCP2   110.0      2.1128       207.51        600.00
CHRNCV26   110.0      1.5383       150.38        600.00
ARGELH25   110.0      1.4017       136.72        600.00
DZRAPP10   110.0      1.3990       134.65        600.00
SPITK_48   110.0      1.3701       132.57        600.00
VANDZOR9   110.0      1.3594       131.30        600.00
VANDZOR8   110.0      1.3590       131.26        600.00
ALVRD12    110.0      1.3226       127.37        600.00
ARZNIH24   110.0      1.2366       120.45        600.00
TAVRZ_50   400.0      1.2291       112.44        177.00
HRZDNSS3   220.0      1.2212       118.40        117.25
ZOVUNI23   110.0      1.1978       116.60        600.00
KANAKR27   110.0      1.1812       114.99        600.00
AMNPP_17   110.0      1.1757       114.27        600.00
ECHMDZ19   110.0      1.1717       115.73        600.00
SHAHMN20   110.0      1.1544       113.54        600.00

Scenario 2-a                                                          1
```

THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES DURING NONFAULT PERIODS.

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
YEGHDZ33	220.0	-4.3398	463.25
YEGHDZ43	110.0	-4.3264	463.50
DZRAPP10	110.0	-4.2945	463.25
HRZDNPP4	10.0	-4.2926	420.00
N	220.0	-4.2924	420.00
TBILIS46	220.0	-4.2898	463.25
ALVRD12	110.0	-4.2840	463.25
HRZDNPP5	110.0	-4.2833	422.00
YERVNP30	110.0	-4.2807	418.50
SEVANPP6	110.0	-4.2764	422.00
HRZDNCP2	110.0	-4.2757	422.00
LICHK_39	220.0	-4.2727	463.50
LICHK_44	110.0	-4.2727	463.50
MXCHAN47	110.0	-4.2682	418.50
ALVRDI11	220.0	-4.2580	463.25
SPNDRN34	220.0	-4.2573	437.00
VANDZOR8	110.0	-4.2521	463.25
VANDZOR9	110.0	-4.2517	463.25
MARASH28	110.0	-4.2501	420.00
CHRNCV26	110.0	-4.2498	422.00

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
YEGHDZ33	220.0		23.9899	600.00
DZRAPP10	110.0	1	5.4523	222.25
SEVANPP6	110.0	1	4.9225	198.75
YERAVN42	6.0	1	4.5647	310.75
HRZDNPP4	10.0	1	4.4881	241.25
KANAKR27	110.0	1	4.4657	356.00
YERVNP30	110.0	1	4.3100	416.50
TBILIS46	220.0	1	4.3037	461.50
ARZNIH24	110.0	1	4.2733	441.00
HRZDNPP1	220.0	1	4.2479	427.75
AGARAK38	220.0	1	4.2312	441.00
SPNDRN34	220.0	1	4.2292	441.00
TATEVP37	110.0	1	4.2168	418.50
SHAMBP35	220.0	1	4.2115	437.00
ARGELH25	110.0	1	4.1194	344.00
AMNPP_18	220.0	1	0.1217	5.50

The following 20 generators have the highest field voltage deviations

GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
SEVANPP6	110.0	1	4.5840	312.75
HRZDNPP4	10.0	1	4.5447	67.50
ARGELH25	110.0	1	3.1440	600.00
AMNPP_18	220.0	1	3.0789	2.00
DZRAPP10	110.0	1	2.8510	600.00
ARZNIH24	110.0	1	2.4214	600.00
TATEVP37	110.0	1	2.3805	71.50
KANAKR27	110.0	1	2.3599	600.00
SHAMBP35	220.0	1	2.3357	332.75
SPNDRN34	220.0	1	2.2915	332.75
YERAVN42	6.0	1	1.7308	600.00
HRZDNPP1	220.0	1	0.9527	209.00
YERVNP30	110.0	1	0.2298	186.25
AGARAK38	220.0	1	0.1305	346.00

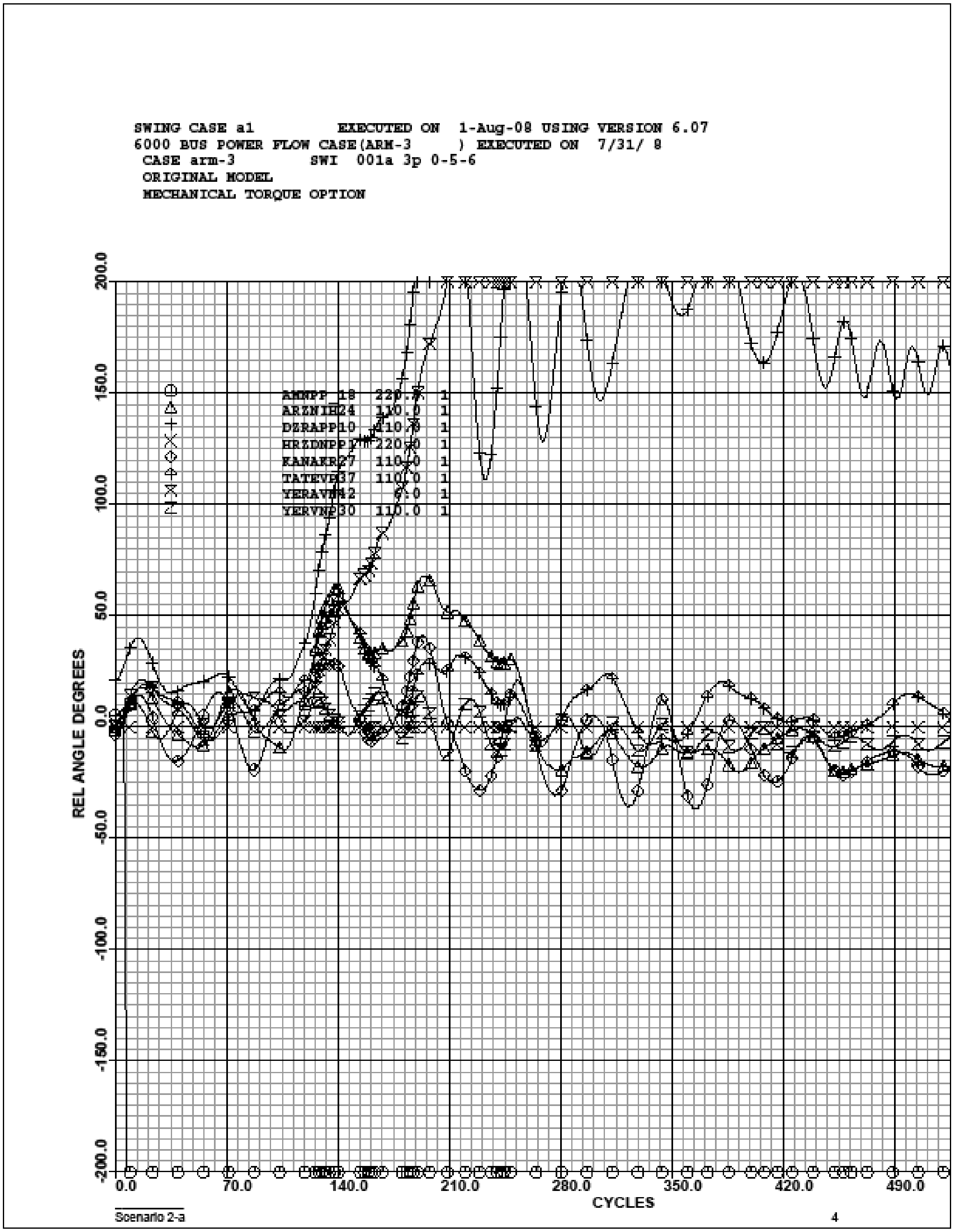
THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

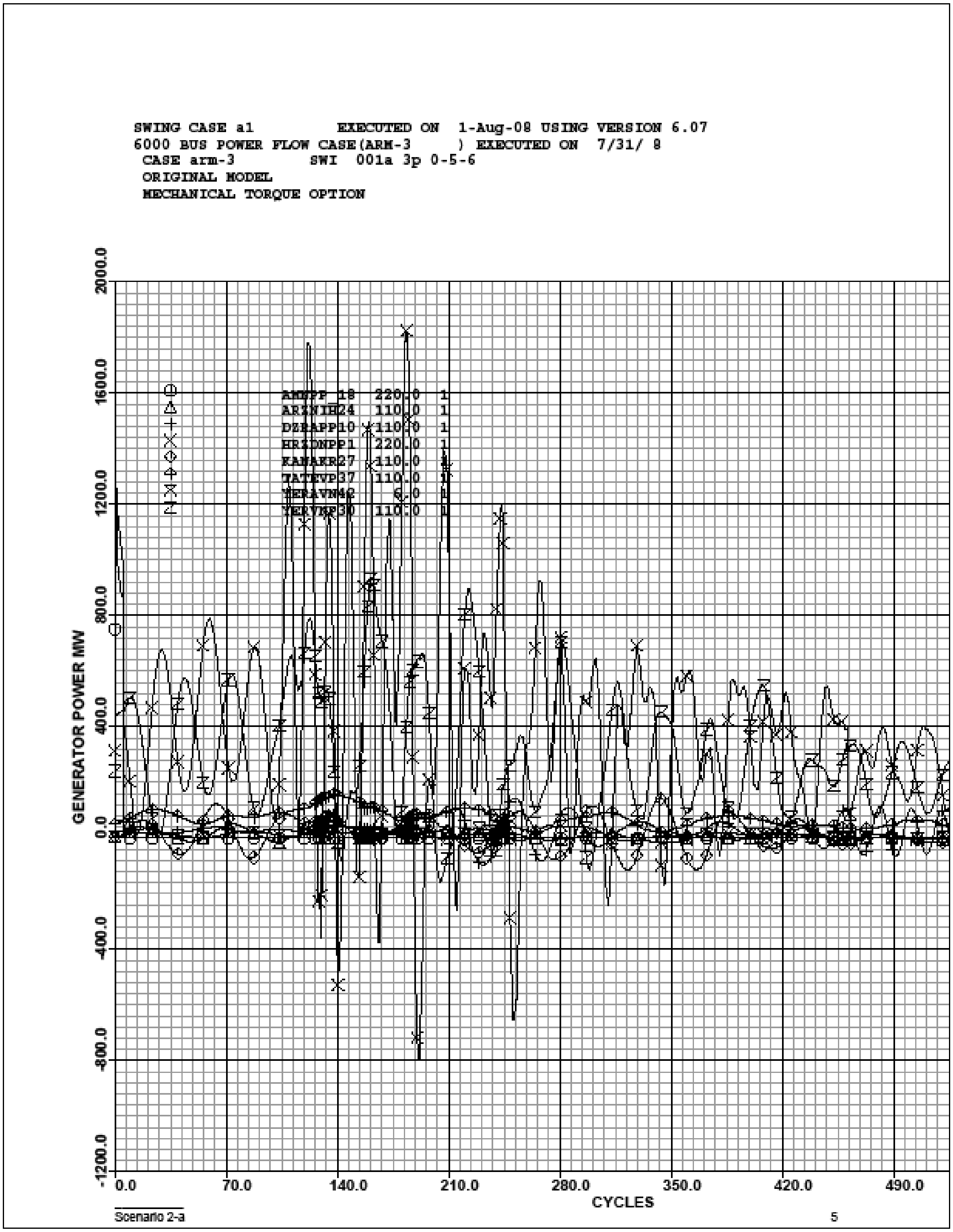
GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
ARGELH25	110.0	1	0.0500	23.50
DZRAPP10	110.0	1	0.0500	27.50
KANAKR27	110.0	1	0.0500	29.50
ARZNIH24	110.0	1	0.0500	37.50
YERAVN42	6.0	1	0.0500	51.50

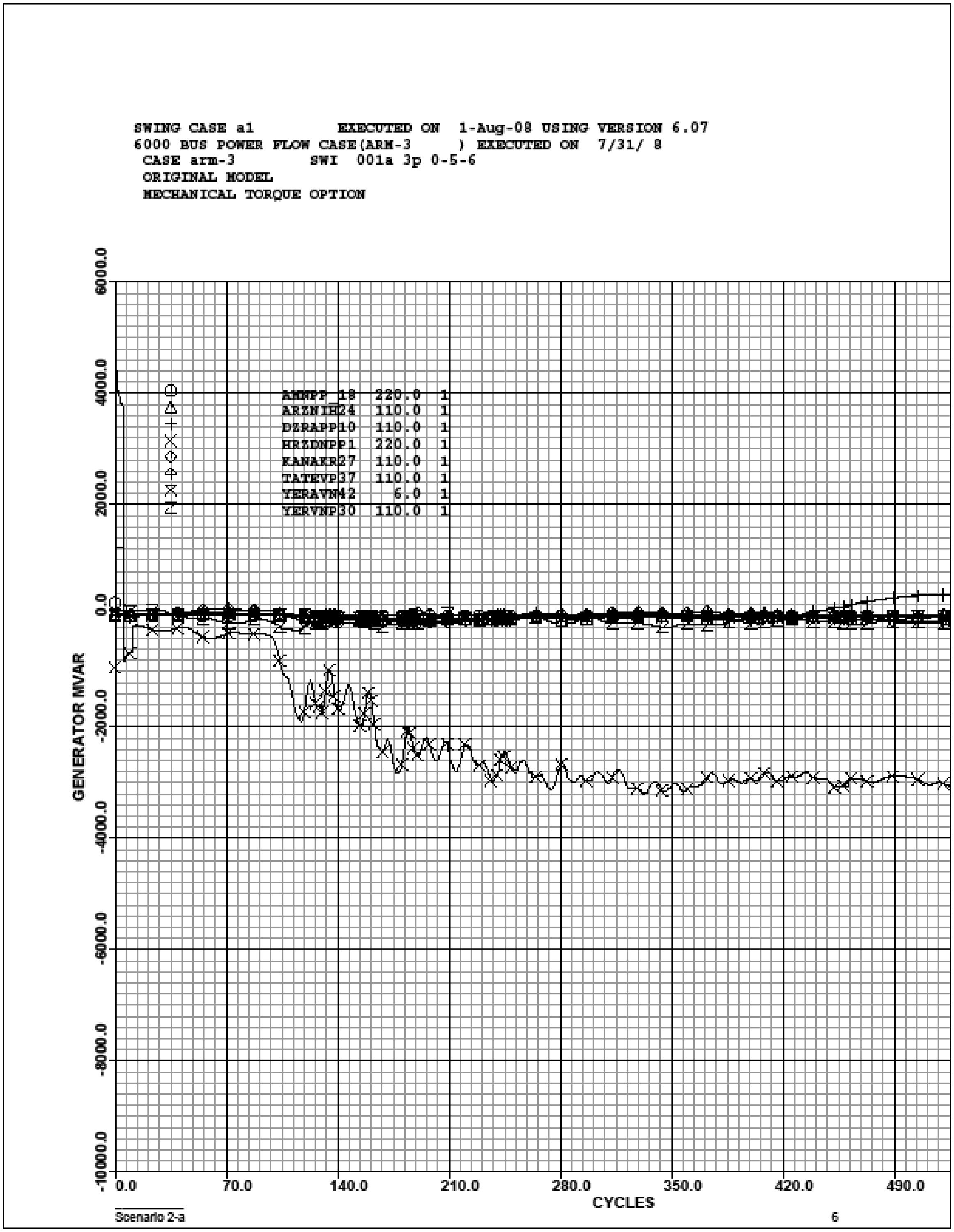
Scenario 2-a 2

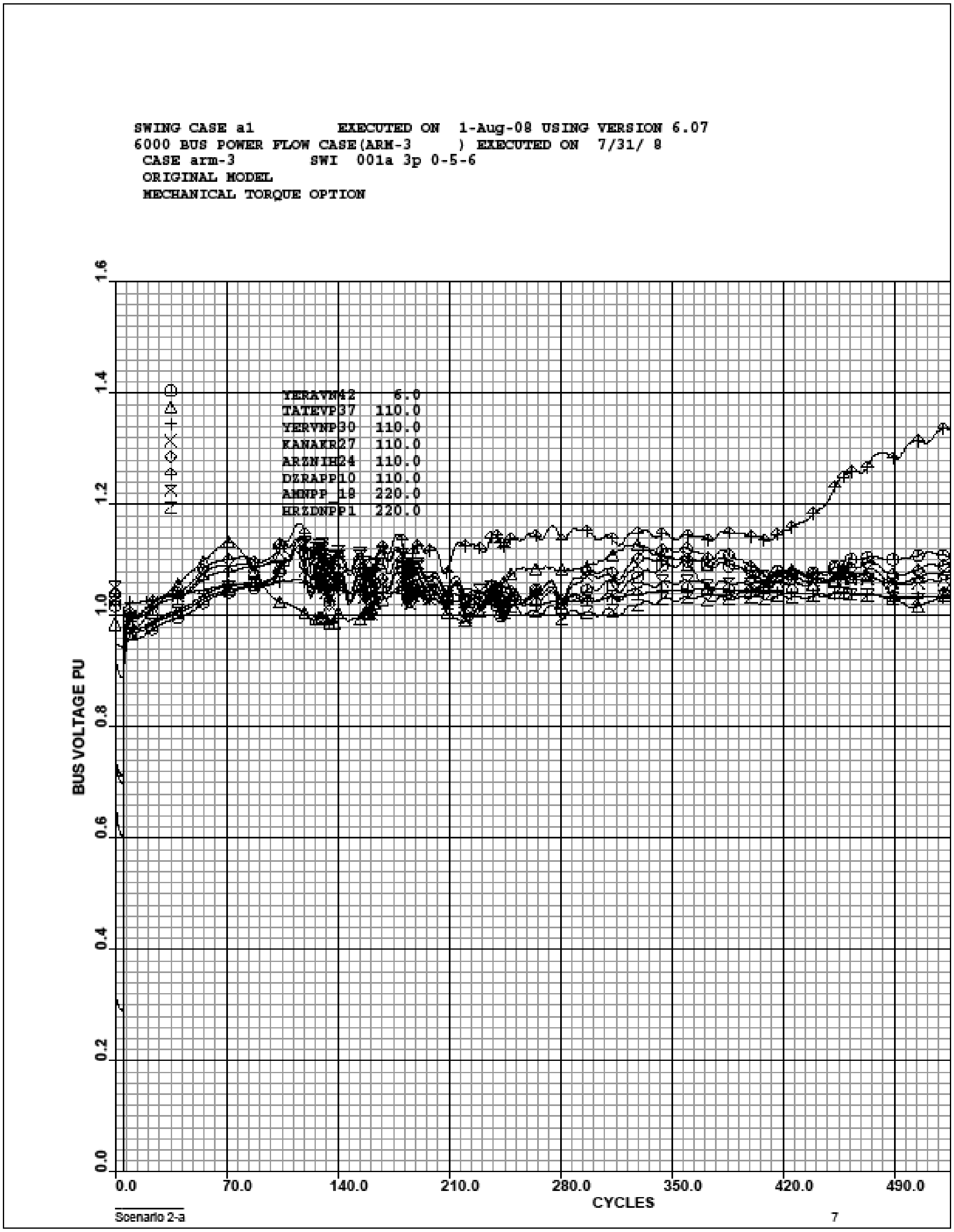
```
SEVANPP6   110.0   1    0.0500         53.50
SHAMBP35   220.0   1    0.0500        164.25
TATEVP37   110.0   1    0.0500        177.00
**********************************************************************
****                                                             ****
****                           VFHIST                            ****
****                                                             ****
****      GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT       ****
****                                                             ****
****           TIME INTERVAL =     0.0 TO   597.0 CYCLES         ****
****                                                             ****
****                                                             ****
**** BASE CASE TITLE:                                            ****
**** ARM-3                                                       ****
**** a1                                                          ****
****                                                             ****
**********************************************************************
------ No-load bus relative voltage dip below    0.0% For entire system -----
-        Bus  name            start    end  elapsed    VLO%     area
cycles  cycles  cycles
[HRAZDN49 400.0]  239.75  342.00  102.25   96.34   1 System
[HRZDNPP1 220.0]  239.75  342.00  102.25   96.39   1 System
[AMNPP_51 400.0]  238.00  330.75   92.75   96.72   1 System
[MARASH29 220.0]  237.75  320.75   83.00   97.41   1 System
[N        220.0]    0.00   63.50   63.50   90.60   1 System
[HRZDNPP4  10.0]    0.00   63.50   63.50   90.62   1 System
[AMNPP_51 400.0]    5.50   67.50   62.00   88.38   1 System
[ASHNAK15 220.0]    5.50   65.50   60.00   88.63   1 System
[HRAZDN49 400.0]    0.00   55.50   55.50   89.20   1 System
[HRZDNPP1 220.0]    0.00   55.50   55.50   89.21   1 System
[HRZDNSS3 220.0]    0.00   55.50   55.50   89.35   1 System
[GYUMRI13 220.0]    5.50   59.50   54.00   89.38   1 System
[SHAHMN21 220.0]    0.00   53.50   53.50   89.57   1 System
[MARASH29 220.0]    0.00   51.50   51.50   91.35   1 System
[YERVNP41 110.0]    0.00   51.50   51.50   89.10   1 System
[ZOVUNI22 220.0]    0.00   49.50   49.50   90.40   1 System
[VANDZOR7 220.0]    5.50   53.50   48.00   90.53   1 System
[ALVRDI11 220.0]    5.50   51.50   46.00   93.63   1 System
[ASHNAK15 220.0]  276.75  320.75   44.00   97.51   1 System
[ARARAT32 220.0]    5.50   47.50   42.00   91.30   1 System
------ Load bus relative voltage dip below    0.0% for entire system -------
Bus  name            start    end  elapsed    vlo%     area
cycles  cycles  cycles
[YERVNP30 110.0]  183.00  320.75  137.75   98.25   1 System
[MXCHAN47 110.0]  193.25  318.75  125.50   98.25   1 System
[AGARAK38 220.0]  103.50  227.25  123.75   98.71   1 System
[AGARAK38 220.0]  360.00  469.50  109.50   99.15   1 System
[TAVRZ_50 400.0]    0.00  109.25  109.25   85.30   1 System
[YERVNP30 110.0]  483.00  581.00   98.00   99.66   1 System
[AMNPP_18 220.0]  238.00  330.75   92.75   96.74   1 System
[AMNPP_18 220.0]    5.50   67.50   62.00   88.36   1 System
[ASHNAK16 110.0]    5.50   65.50   60.00   88.62   1 System
[ARARAT31 110.0]  217.00  272.75   55.75   98.26   1 System
[GYUMRI14 110.0]    5.50   59.50   54.00   89.38   1 System
[HAGHTK45 220.0]    0.00   53.50   53.50   89.64   1 System
[ECHMDZ19 110.0]    0.00   53.50   53.50   89.08   1 System
[AMNPP_17 110.0]    0.00   53.50   53.50   89.06   1 System
[YERAVN42   6.0]    0.00   51.50   51.50   89.05   1 System
[SHAHMN20 110.0]    0.00   51.50   51.50   89.14   1 System
[HRZDNPP5 110.0]    0.00   49.50   49.50   91.32   1 System
[GAVAR_40 220.0]    0.00   47.50   47.50   90.73   1 System
[SEVANPP6 110.0]    0.00   45.50   45.50   91.75   1 System
[ARARAT31 110.0]    0.00   45.50   45.50   95.07   1 System
```

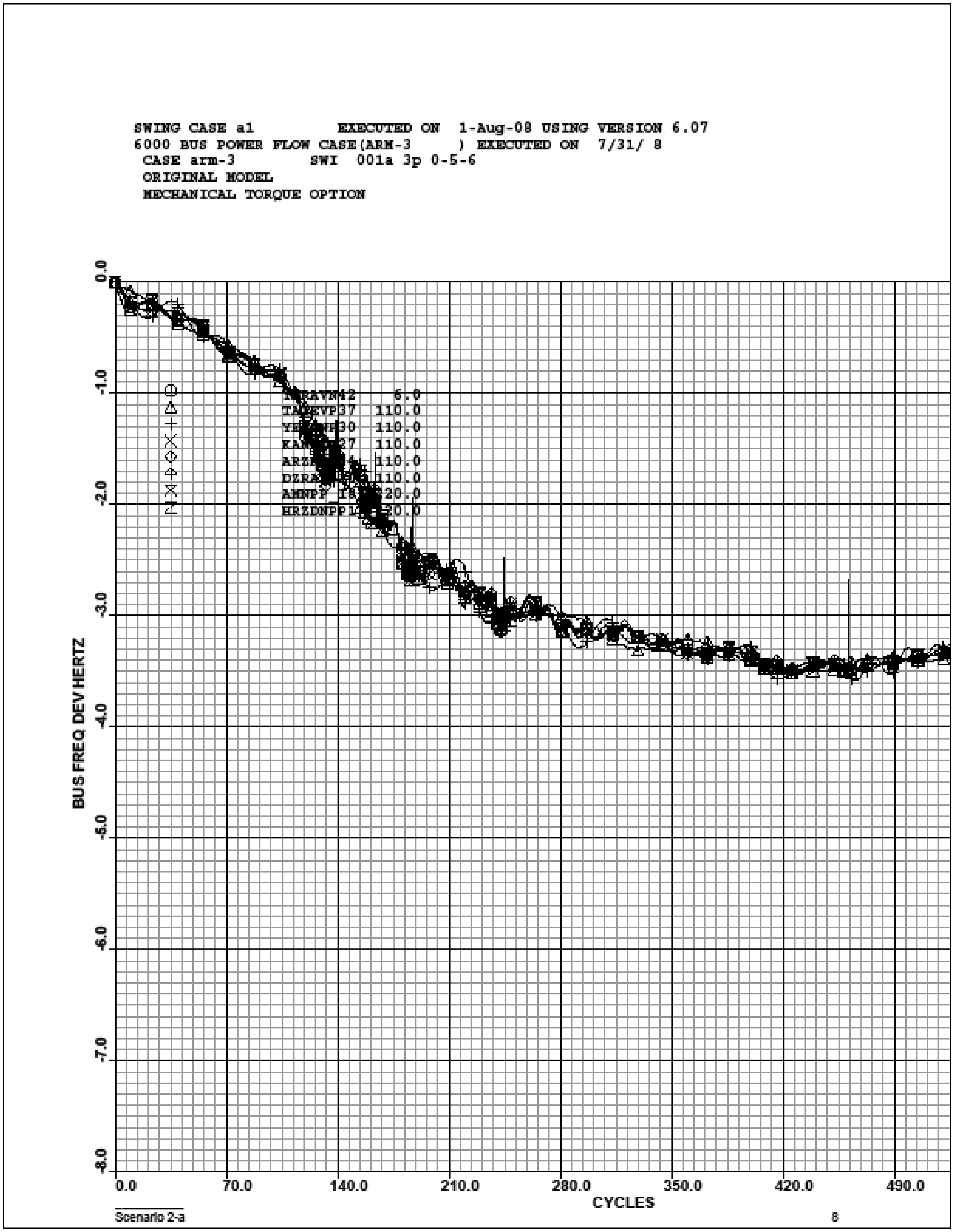
Scenario 2-a   3


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP 18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
200.0
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 2-a
4


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
GENERATOR POWER MW
CYCLES
Scenario 2-a
5


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
6000.0
4000.0
2000.0
0.0
-2000.0
-4000.0
-6000.0
-8000.0
-10000.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 2-a
6


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
AMNPP_18 220.0
HRZDNPP1 220.0
BUS VOLTAGE PU
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 2-a
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
BUS FREQ DEV HERTZ
0.0
-1.0
-2.0
-3.0
-4.0
-5.0
-6.0
-7.0
-8.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 2-a
8

1.5 APPENDIX 4.2.B

```
Scenario 2.       2017 Summer MIN
                  Short circuit on bus-bar of HVL-400 kV Tabriz with tripping HVL
                  Disconnection of ANPP
SWING CASE a1         EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  7/31/ 8
CASE arm-3        SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3      8  1  1
F1                    1
LS  HRAZDN49 400  TAVRZ_50 400 1    2    0.0
LS -HRAZDN49 400 -TAVRZ_50 400 1   -2    5.5
LS  AMNPP_18 2201                   4    11.5                          9
FF      .25 0600.                                       50       0  1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES
THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
TAVRZ_50   400.0      0.7473        68.37          5.50
HRZDNPP1   220.0      0.8159        79.14          5.50
HRAZDN49   400.0      0.8182        79.22          5.50
HRZDNSS3   220.0      0.8274        80.22          5.50
N          220.0      0.8509        83.26          5.50
HRZDNPP4    10.0      0.8510        83.26          5.50
GAVAR_40   220.0      0.8601        83.43          5.50
VANDZOR7   220.0      0.8648        83.38          5.50
HRZDNPP5   110.0      0.8686        85.45          5.50
SEVANPP6   110.0      0.8795        86.36          5.50
LICHK_44   110.0      0.8815        85.76          5.50
LICHK_39   220.0      0.8843        85.76          5.50
HRZDNCP2   110.0      0.8872        87.14          5.50
VANDZOR8   110.0      0.8894        85.90          5.50
VANDZOR9   110.0      0.8898        85.94          5.50
SHAHMN20   110.0      0.8918        87.71          5.50
ECHMDZ19   110.0      0.8920        88.11          5.50
ZOVUNI22   220.0      0.8922        86.20          5.50
YERVNP41   110.0      0.8927        87.75          5.50
YERAVN42     6.0      0.8935        87.78          5.50
THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
TAVRZ_50   400.0      1.1424       104.51        358.25
TATEVP37   110.0      1.1334       115.08         75.50
SHAMBP35   220.0      1.1308       111.24         75.50
ARGELH25   110.0      1.1243       109.66         77.50
SPNDRN34   220.0      1.1189       109.65         77.50
CHRNCV26   110.0      1.1143       108.93        403.00
ARZNIH24   110.0      1.1116       108.27        407.00
SHNHYR36   220.0      1.1068       109.39         75.50
ZOVUNI23   110.0      1.1051       107.59        407.00
KANAKR27   110.0      1.1048       107.55        407.00
YEGHDZ33   220.0      1.1002       106.69         79.50
YEGHDZ43   110.0      1.0968       106.69         79.50
SPITK_48   110.0      1.0938       105.84        407.00
DZRAPP10   110.0      1.0929       105.19        201.00
SEVANPP6   110.0      1.0856       106.60        203.00
VANDZOR9   110.0      1.0847       104.77        407.00
ALVRD12    110.0      1.0845       104.44        201.00
VANDZOR8   110.0      1.0844       104.73        407.00
LICHK_39   220.0      1.0844       105.17         81.50
HRZDNCP2   110.0      1.0833       106.40        203.00
THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES
DURING NONFAULT PERIODS.
```

Scenario 2-b 1

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
YEGHDZ33	220.0	-2.4339	339.00
YEGHDZ43	110.0	-2.4339	339.00
SPNDRN34	220.0	-2.3953	339.00
SHAMBP35	220.0	-2.3848	339.00
SHNHYR36	220.0	-2.3810	339.00
TATEVP37	110.0	-2.3765	339.00
LICHK_39	220.0	-2.3738	339.00
LICHK_44	110.0	-2.3737	339.00
AGARAK38	220.0	-2.3619	339.00
GAVAR_40	220.0	-2.3411	339.00
ARARAT32	220.0	-2.3377	339.00
YERVNP30	110.0	-2.3327	377.00
MXCHAN47	110.0	-2.3234	377.00
TBILIS46	220.0	-2.3232	338.75
TAVRZ_50	400.0	-2.3217	360.25
HRZDNPP1	220.0	-2.3209	360.25
HRAZDN49	400.0	-2.3207	360.25
HRZDNSS3	220.0	-2.3177	360.25
VANDZOR7	220.0	-2.3108	360.25
AMNPP_51	400.0	-2.3104	363.50

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
YEGHDZ33	220.0		21.7622	599.00
HRZDNPP4	10.0	1	2.7857	209.00
SEVANPP6	110.0	1	2.5816	313.00
YERAVN42	6.0	1	2.4866	317.00
ARZNIH24	110.0	1	2.4478	307.00
TATEVP37	110.0	1	2.4003	337.50
SHAMBP35	220.0	1	2.3680	340.50
SPNDRN34	220.0	1	2.3646	340.50
AGARAK38	220.0	1	2.3617	340.50
YERVNP30	110.0	1	2.3553	375.00
HRZDNPP1	220.0	1	2.3402	360.25
TBILIS46	220.0	1	2.3366	343.25
DZRAPP10	110.0	1	2.3202	343.25
ARGELH25	110.0	1	2.3045	343.25
KANAKR27	110.0	1	2.2856	330.25
AMNPP_18	220.0	1	0.1942	9.50

The following 20 generators have the highest field voltage deviations

GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
HRZDNPP4	10.0	1	4.4886	71.50
AMNPP_18	220.0	1	3.0789	2.00
TATEVP37	110.0	1	2.3819	75.50
SHAMBP35	220.0	1	2.3270	75.50
ARGELH25	110.0	1	2.2867	77.50
SPNDRN34	220.0	1	2.2813	77.50
SEVANPP6	110.0	1	2.1831	203.00
KANAKR27	110.0	1	2.1237	407.00
ARZNIH24	110.0	1	2.0350	407.00
DZRAPP10	110.0	1	1.9051	201.00
YERAVN42	6.0	1	1.5067	407.00
HRZDNPP1	220.0	1	0.7137	53.50
YERVNP30	110.0	1	0.1906	19.50
AGARAK38	220.0	1	0.1307	97.50

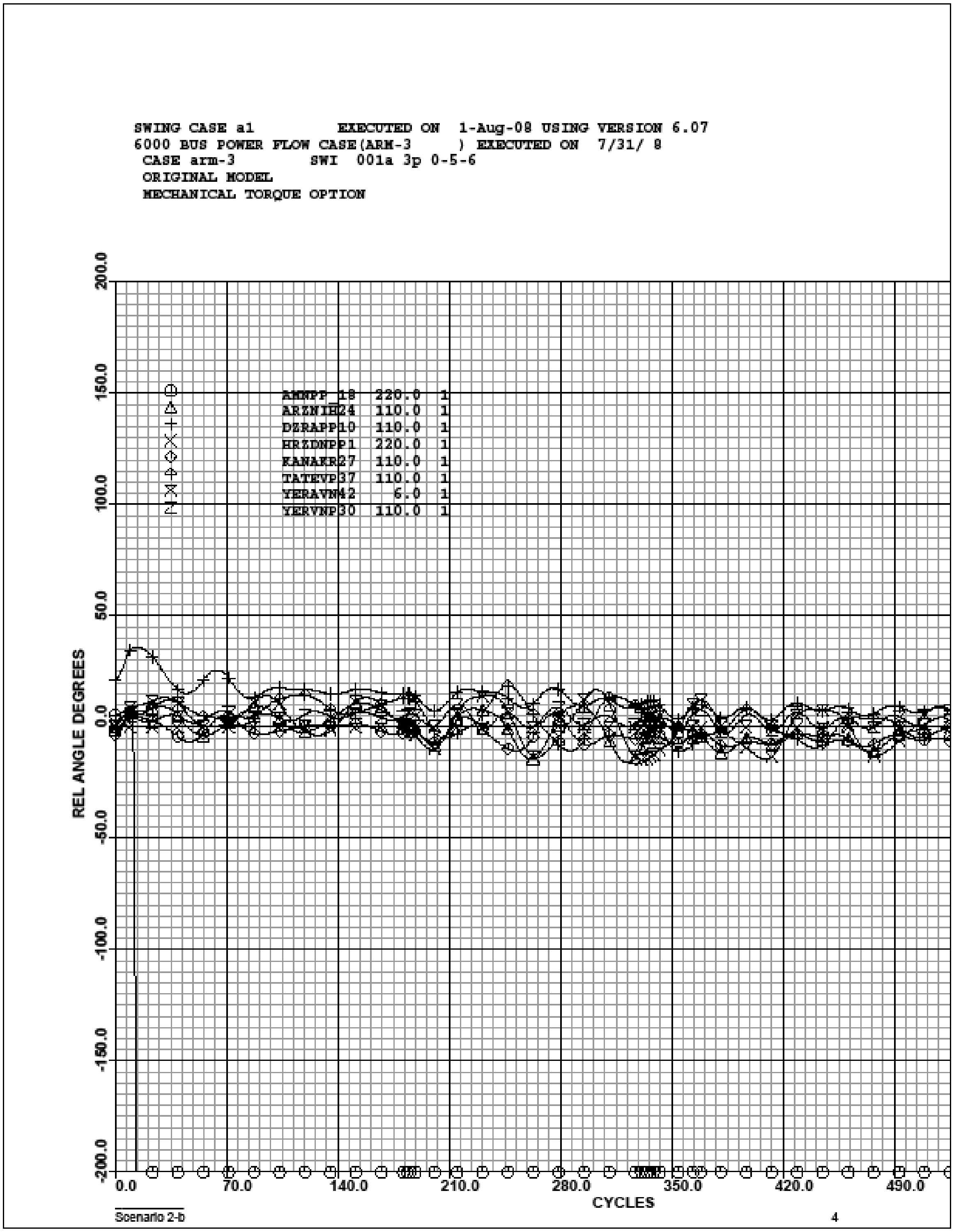
THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

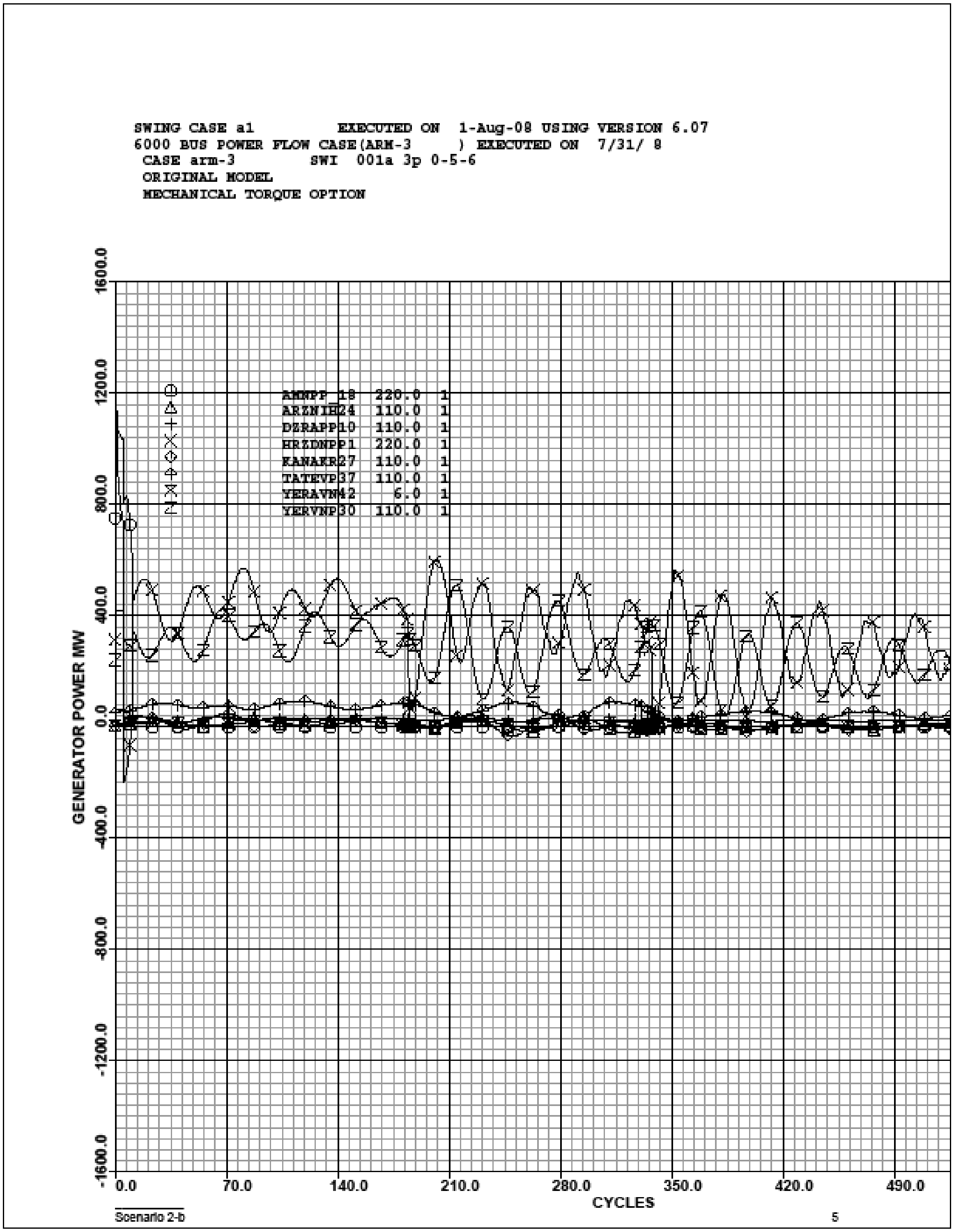
GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
DZRAPP10	110.0	1	0.0500	31.50
KANAKR27	110.0	1	0.0500	39.50
YERAVN42	6.0	1	0.0500	117.50
SEVANPP6	110.0	1	0.0500	181.00
ARZNIH24	110.0	1	0.0500	187.50
ARGELH25	110.0	1	0.0500	192.75
SHAMBP35	220.0	1	0.0500	194.75

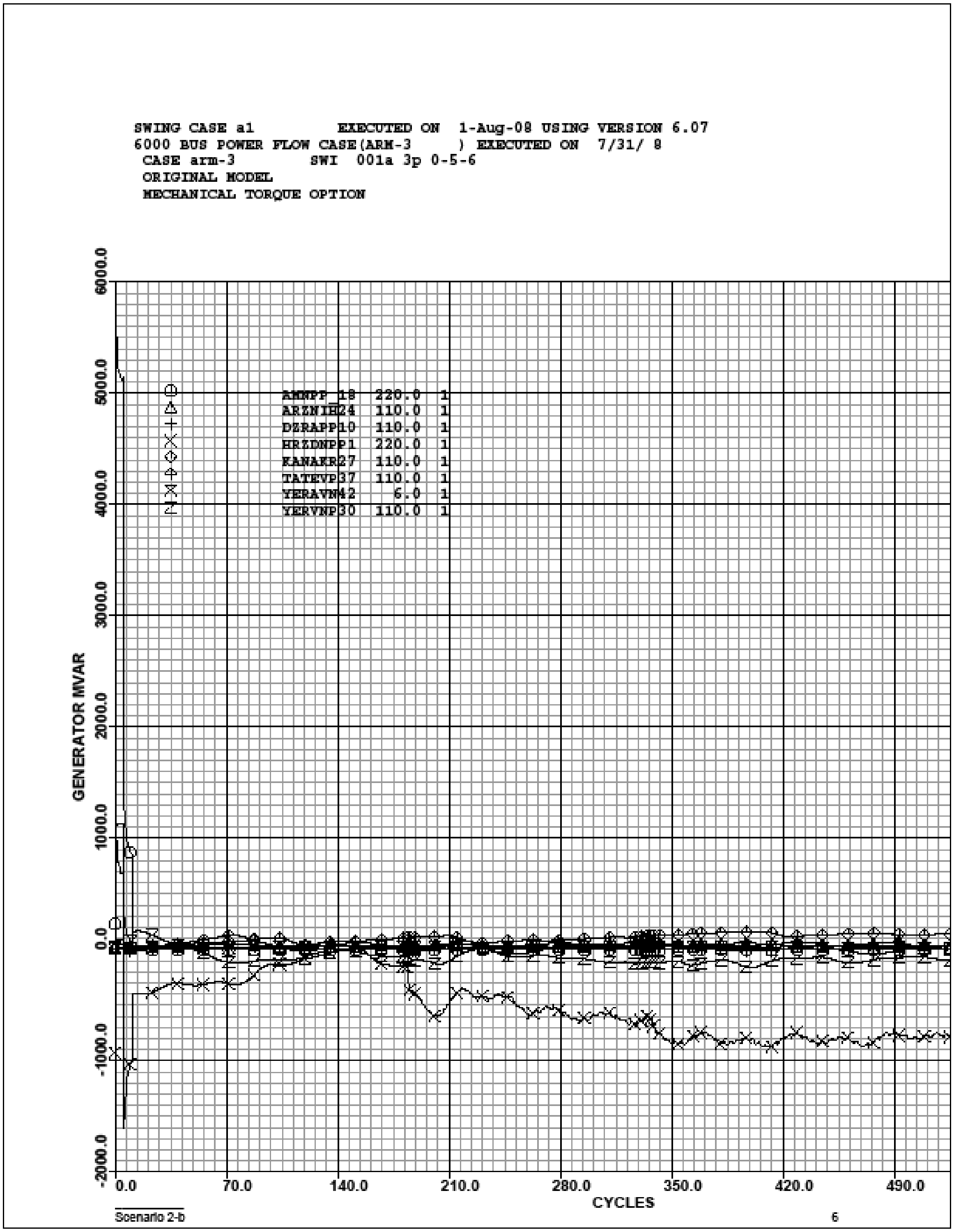
Scenario 2-b 2

```
TATEVP37   110.0   1    0.0500         201.00
*********************************************************************
****                                                             ****
****                          VFHIST                             ****
****                                                             ****
****       GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT      ****
****                                                             ****
****            TIME INTERVAL =     0.0 TO   597.0 CYCLES        ****
****                                                             ****
****                                                             ****
**** BASE CASE TITLE:                                            ****
**** ARM-3                                                       ****
**** a1                                                          ****
****                                                             ****
*********************************************************************
------ No-load bus relative voltage dip below     0.0% For entire system -----
-        Bus  name             start    end  elapsed    VLO%     area
cycles  cycles  cycles
[AMNPP_51 400.0]  409.00  600.00  191.00   98.33   1 System
[ASHNAK15 220.0]  419.00  600.00  181.00   98.70   1 System
[HRAZDN49 400.0]  425.00  587.00  162.00   99.20   1 System
[AMNPP_51 400.0]  211.00  348.25  137.25   97.81   1 System
[ASHNAK15 220.0]  213.00  340.25  127.25   98.07   1 System
[HRZDNPP1 220.0]  445.00  561.00  116.00   99.26   1 System
[HRAZDN49 400.0]  229.00  338.00  109.00   99.16   1 System
[GYUMRI13 220.0]  217.00  325.00  108.00   98.75   1 System
[HRZDNPP1 220.0]  231.00  338.00  107.00   99.25   1 System
[MARASH29 220.0]  215.00  317.00  102.00   98.95   1 System
[HRZDNSS3 220.0]  229.00  327.00   98.00   99.27   1 System
[HRZDNPP4  10.0]    0.00   77.50   77.50   83.26   1 System
[N        220.0]    0.00   77.50   77.50   83.26   1 System
[N        220.0]  267.00  343.25   76.25   98.58   1 System
[HRZDNPP4  10.0]  269.00  343.25   74.25   98.58   1 System
[SHAHMN21 220.0]  217.00  289.00   72.00   99.00   1 System
[N        220.0]  109.50  181.00   71.50   92.44   1 System
[HRZDNPP4  10.0]  109.50  179.50   70.00   92.41   1 System
[ASHNAK15 220.0]    5.50   67.50   62.00   88.66   1 System
[AMNPP_51 400.0]    5.50   67.50   62.00   89.04   1 System
------ Load bus relative voltage dip below     0.0% for entire system -------
Bus  name             start    end  elapsed    vlo%     area
cycles  cycles  cycles
[AMNPP_18 220.0]  409.00  600.00  191.00   98.31   1 System
[TAVRZ_50 400.0]    0.00  184.50  184.50   68.37   1 System
[AGARAK38 220.0]  107.50  251.00  143.50   99.10   1 System
[AMNPP_18 220.0]  211.00  348.25  137.25   97.76   1 System
[TAVRZ_50 400.0]  213.00  338.00  125.00   97.70   1 System
[AGARAK38 220.0]  383.00  503.00  120.00   99.39   1 System
[YERVNP30 110.0]  481.00  600.00  119.00   99.60   1 System
[YERVNP30 110.0]  209.00  321.00  112.00   98.72   1 System
[MXCHAN47 110.0]  483.00  595.00  112.00   99.67   1 System
[ASHNAK16 110.0]  217.00  325.00  108.00   98.78   1 System
[MXCHAN47 110.0]  209.00  317.00  108.00   98.77   1 System
[GYUMRI14 110.0]  217.00  321.00  104.00   98.90   1 System
[ARARAT31 110.0]  215.00  291.00   76.00   98.77   1 System
[HAGHTK45 220.0]  217.00  285.00   68.00   99.00   1 System
[ASHNAK16 110.0]    5.50   67.50   62.00   88.65   1 System
[AMNPP_18 220.0]    5.50   67.50   62.00   89.43   1 System
[GYUMRI14 110.0]    5.50   63.50   58.00   86.56   1 System
[HAGHTK45 220.0]    0.00   57.50   57.50   86.84   1 System
[AMNPP_17 110.0]    0.00   57.50   57.50   89.00   1 System
[SHAHMN20 110.0]    0.00   55.50   55.50   87.71   1 System
```

Scenario 2-b 3


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
200.0
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 2-b
4


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR POWER MW
1600.0
1200.0
800.0
400.0
0.0
-400.0
-800.0
-1200.0
-1600.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 2-b
5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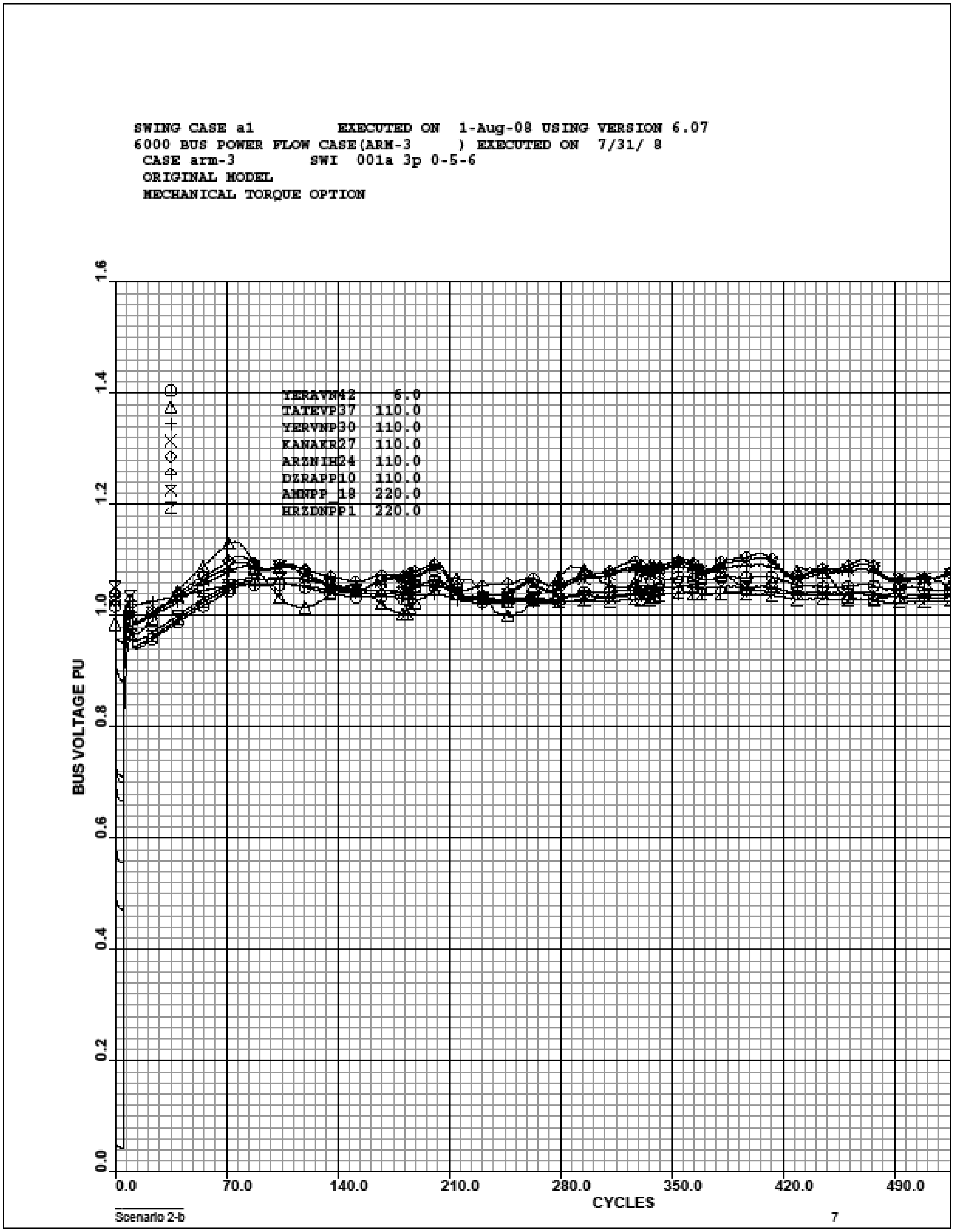
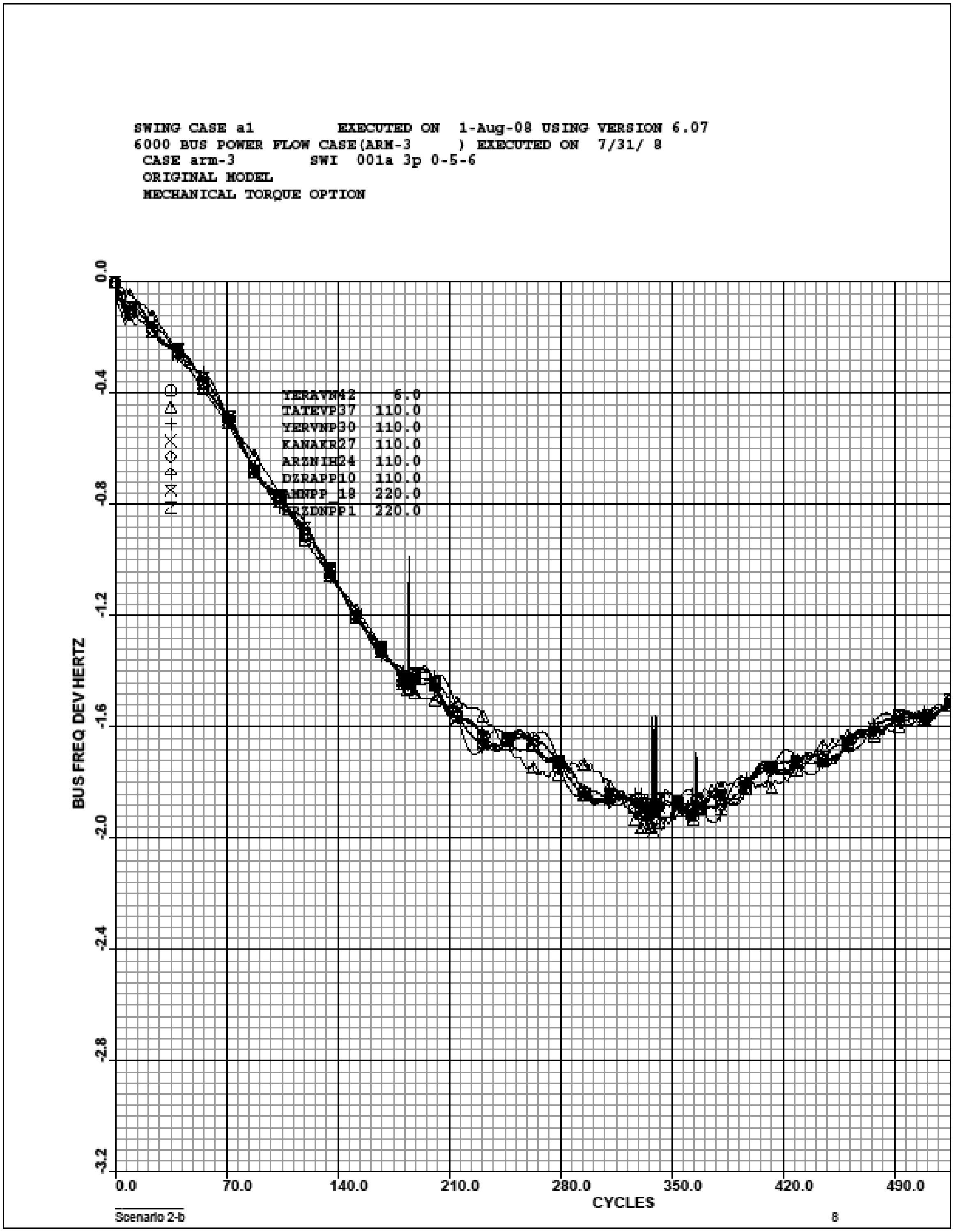
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
-2000.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 2-b
6


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVNM42 6.0
TATEVP37 110.0
YERVNP30 110.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
AMNPP_18 220.0
HRZDNPP1 220.0
BUS VOLTAGE PU
CYCLES
Scenario 2-b
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 7/31/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
AMNPP_18 220.0
ARZDNPP1 220.0
BUS FREQ DEV HERTZ
CYCLES
Scenario 2-b
8

1.6 APPENDIX 4.3.A

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Scenario 3.        2030 Winter MAX
                   Short circuit on ANPP's bus-bar with tripping ANPP
                   Disconnection of HVL-400 kV Tabriz
SWING CASE a1          EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  8/ 1/ 8
CASE arm-3         SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3       8  1  1
F1                     1
LS  AMNPP_18 220  ARARAT32 220 1    2    0.0
LS  AMNPP_18 220  ARARAT32 220 1   -2    5.5
LS  AMNPP_18 2201                   4    5.5                         9
LS -HRAZDN49 400 -TAVRZ_50 400 1         11.5
FF      .25 0600.                                  50      0   1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES                               THE
FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
HRZDNPP5   110.0      0.8184        90.33          5.50
SEVANPP6   110.0      0.8223        90.76          5.50
ECHMDZ19   110.0      0.8255        86.71          5.50
HRZDNCP2   110.0      0.8282        91.10          5.50
GYUMRI14   110.0      0.8338        87.64          5.50
ASHNAK16   110.0      0.8365        86.46          5.50
YERAVN42     6.0      0.8381        86.50          5.50
YERVNP41   110.0      0.8390        86.64          5.50
SHAHMN20   110.0      0.8399        86.78          5.50
HRZDNPP4    10.0      0.8492        89.62          5.50
N          220.0      0.8492        89.62          5.50
AMNPP_17   110.0      0.8644        87.02          5.50
GYUMRI13   220.0      0.8712        87.70          5.50
ALVRD12    110.0      0.8781        91.99          5.50
DZRAPP10   110.0      0.8865        91.47          5.50
ASHNAK15   220.0      0.8913        86.59          5.50
VANDZOR8   110.0      0.8913        90.89          5.50
VANDZOR9   110.0      0.8915        90.90          5.50
CHRNCV26   110.0      0.8942        92.87          5.50
SPITK_48   110.0      0.8959        91.42          5.50
THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
TATEVP37   110.0      1.1625       121.05        318.50
TAVRZ_50   400.0      1.1511       103.99        136.00
SHAMBP35   220.0      1.1469       113.58        318.50
ARGELH25   110.0      1.1358       115.64        332.25
SPNDRN34   220.0      1.1307       111.49        322.50
SHNHYR36   220.0      1.1199       111.67        318.50
ARZNIH24   110.0      1.1192       112.29        332.25
CHRNCV26   110.0      1.1137       115.66        332.25
ZOVUNI23   110.0      1.1089       110.81        334.25
KANAKR27   110.0      1.1073       110.41        334.25
YEGHDZ33   220.0      1.0954       107.78        132.00
YEGHDZ43   110.0      1.0859       108.42        132.00
LICHK_39   220.0      1.0846       106.86        132.00
GAVAR_40   220.0      1.0829       106.12        134.00
HRAZDN49   400.0      1.0805       104.61        136.00
SPITK_48   110.0      1.0804       110.23        344.00
HRZDNPP1   220.0      1.0797       104.72        136.00
ZOVUNI22   220.0      1.0788       106.05        136.00
HRZDNSS3   220.0      1.0769       105.14        136.00
ARARAT32   220.0      1.0762       105.11        134.00
THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES
```

Scenario-3-a 1

DURING NONFAULT PERIODS.

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
TBILIS46	220.0	-2.3383	348.00
YERVNP30	110.0	-2.3083	326.50
MXCHAN47	110.0	-2.3036	326.50
ALVRDI11	220.0	-2.2977	341.50
AGARAK38	220.0	-2.2957	311.50
MARASH28	110.0	-2.2948	326.50
TATEVP37	110.0	-2.2919	313.25
SHNHYR36	220.0	-2.2919	313.25
SHAMBP35	220.0	-2.2910	313.25
SPNDRN34	220.0	-2.2899	313.25
ARARAT31	110.0	-2.2893	326.50
ALVRD12	110.0	-2.2868	339.75
VANDZOR7	220.0	-2.2841	338.50
YEGHDZ33	220.0	-2.2838	313.25
YEGHDZ43	110.0	-2.2837	313.25
KANAKR27	110.0	-2.2833	325.50
HRZDNPP1	220.0	-2.2830	337.75
TAVRZ_50	400.0	-2.2829	337.75
HRAZDN49	400.0	-2.2829	337.75
DZRAPP10	110.0	-2.2827	338.50

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
YEGHDZ33	220.0		2.8668	326.50
SEVANPP6	110.0	1	2.4088	339.75
YERAVN42	6.0	1	2.3931	325.50
TBILIS46	220.0	1	2.3750	352.00
ARZNIH24	110.0	1	2.3473	320.50
YERVNP30	110.0	1	2.3173	325.50
KANAKR27	110.0	1	2.3167	320.50
SPNDRN34	220.0	1	2.3131	313.25
TATEVP37	110.0	1	2.2990	313.25
AGARAK38	220.0	1	2.2978	310.25
SHAMBP35	220.0	1	2.2966	313.25
ARGELH25	110.0	1	2.2931	320.50
HRZDNPP1	220.0	1	2.2900	337.75
DZRAPP10	110.0	1	2.2866	325.50
AMNPP_18	220.0	1	0.0256	2.00

The following 20 generators have the highest field voltage deviations

GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
AMNPP_18	220.0	1	2.9898	2.00
ARGELH25	110.0	1	2.3877	332.25
SHAMBP35	220.0	1	2.3060	318.50
SEVANPP6	110.0	1	2.2797	332.25
DZRAPP10	110.0	1	2.1275	346.00
TATEVP37	110.0	1	2.1163	318.50
KANAKR27	110.0	1	2.0351	334.25
SPNDRN34	220.0	1	1.9772	322.50
ARZNIH24	110.0	1	1.9449	332.25
YERAVN42	6.0	1	1.6062	5.50
HRZDNPP1	220.0	1	0.6258	55.50
YERVNP30	110.0	1	0.2698	166.00
AGARAK38	220.0	1	0.1604	134.00

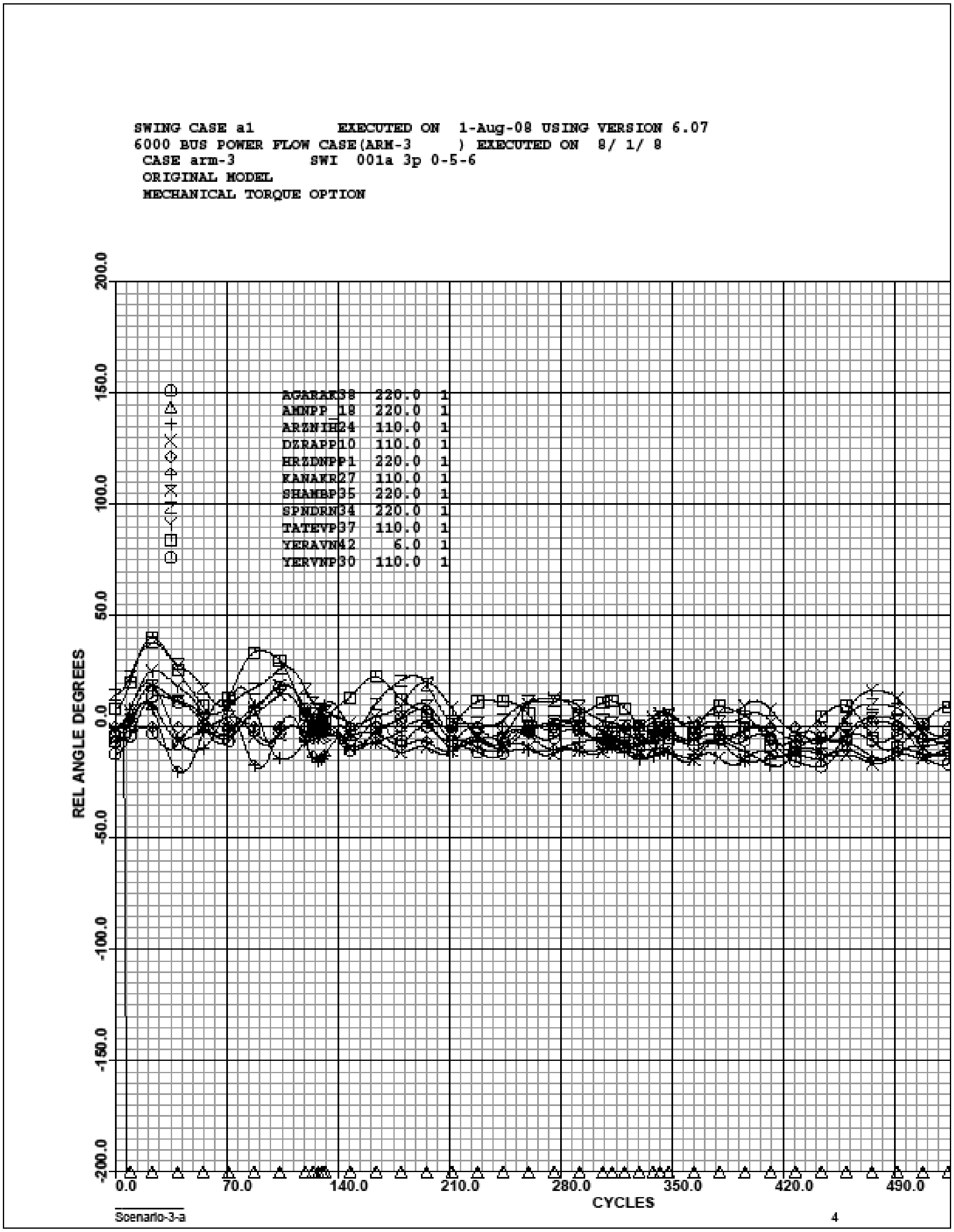
THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

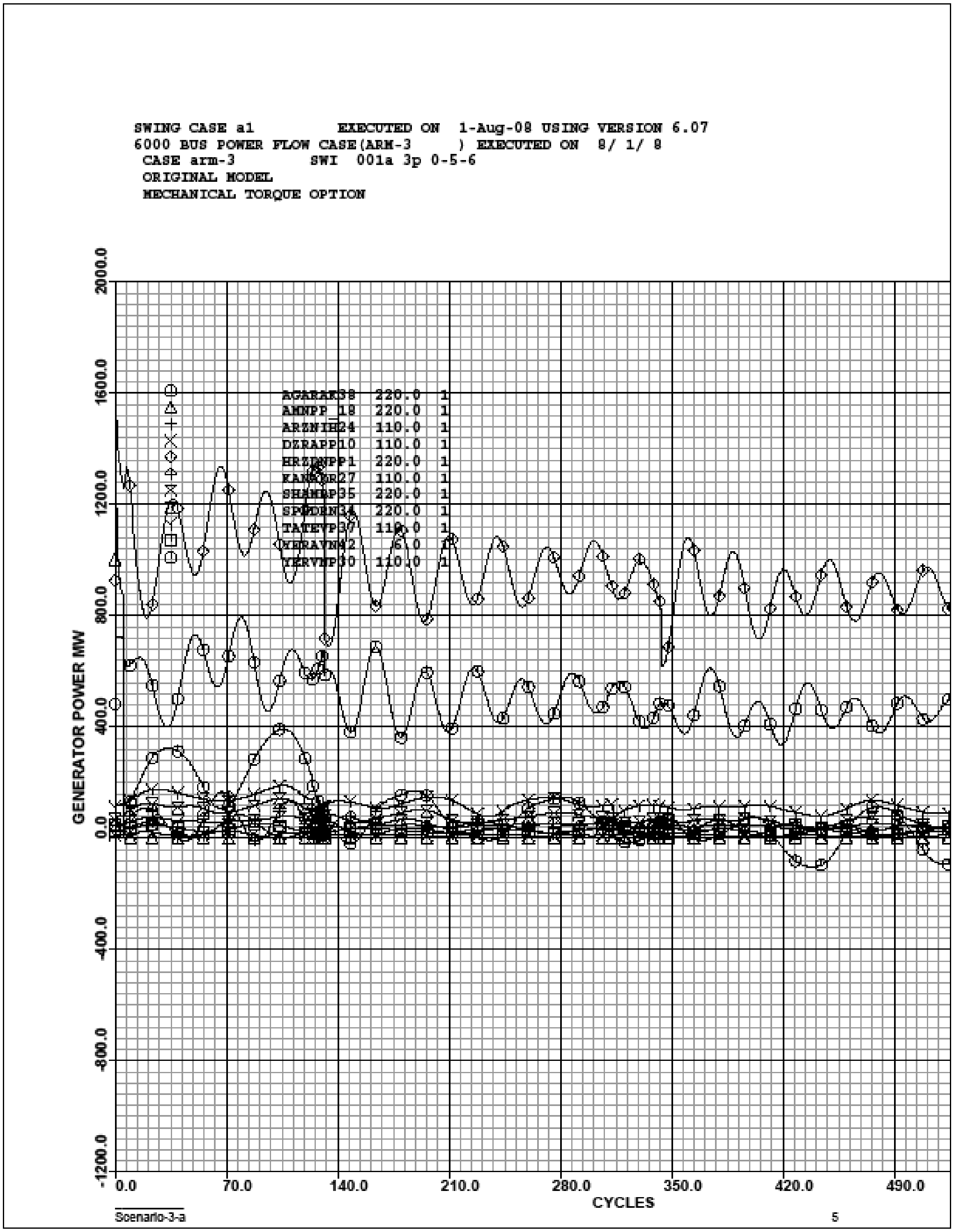
GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
ARGELH25	110.0	1	0.0500	27.50
KANAKR27	110.0	1	0.0500	33.50
DZRAPP10	110.0	1	0.0500	35.50
ARZNIH24	110.0	1	0.0500	39.50
YERAVN42	6.0	1	0.0500	51.50
SEVANPP6	110.0	1	0.0500	120.50
TATEVP37	110.0	1	0.0500	168.00
SHAMBP35	220.0	1	0.0500	210.00

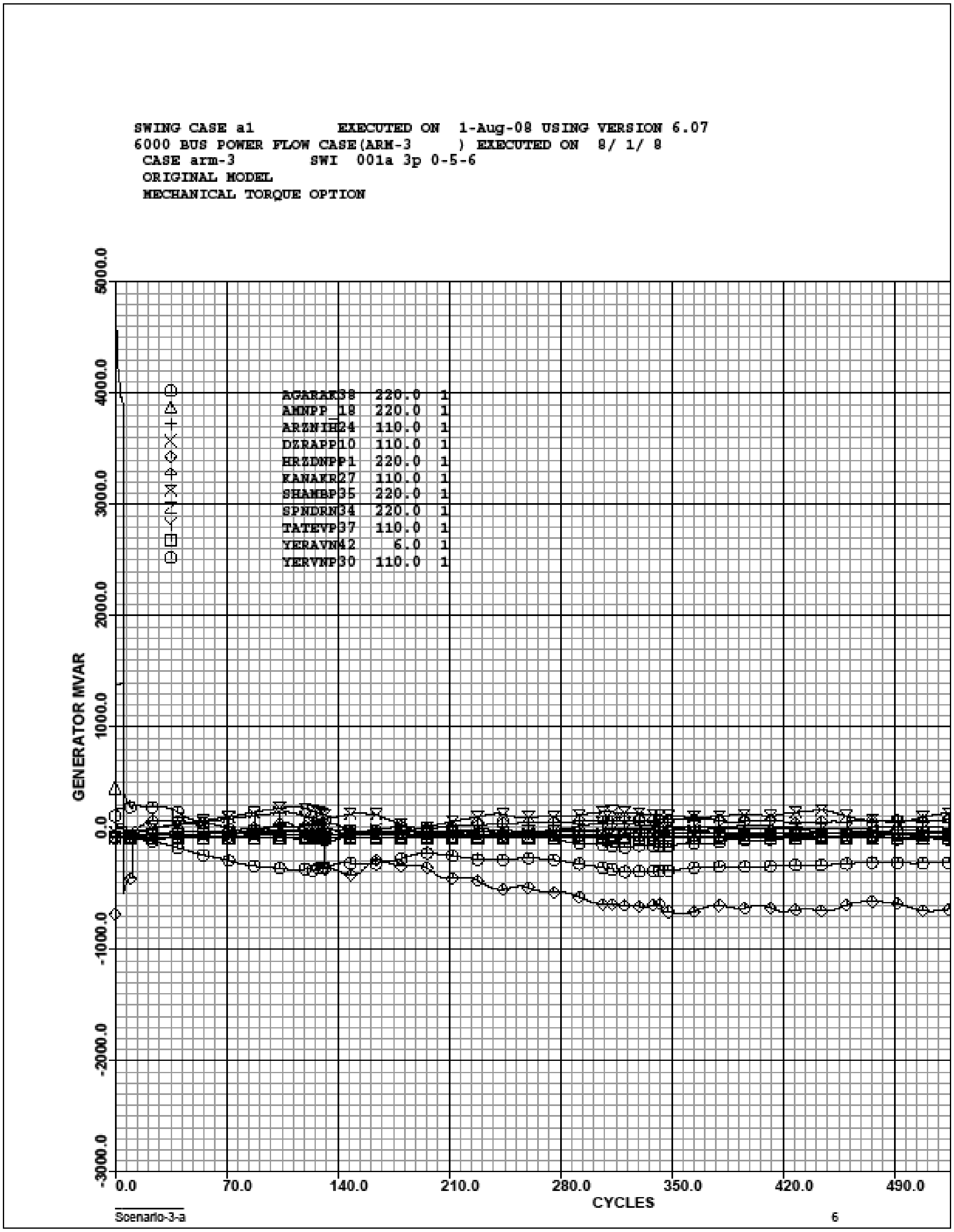
Scenario-3-a 2

```
*********************************************************************
****                                                            ****
****                          VFHIST                            ****
****                                                            ****
****      GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT      ****
****                                                            ****
****          TIME INTERVAL =     0.0 TO   596.0 CYCLES         ****
****                                                            ****
****                                                            ****
**** BASE CASE TITLE:                                           ****
**** ARM-3                                                      ****
**** a1                                                         ****
****                                                            ****
*********************************************************************
------ No-load bus relative voltage dip below     0.0% For entire system -----
-        Bus  name            start    end   elapsed    VLO%     area
cycles  cycles  cycles
[AMNPP_51 400.0]  170.00  600.00  430.00   97.36   1 System
[ASHNAK15 220.0]  374.00  600.00  226.00   98.82   1 System
[ASHNAK15 220.0]  184.00  316.50  132.50   98.34   1 System
[AMNPP_51 400.0]    5.50  109.50  104.00   86.27   1 System
[HRAZDN49 400.0]  208.00  310.25  102.25   98.89   1 System
[ASHNAK15 220.0]    5.50  105.50  100.00   86.59   1 System
[HRZDNPP1 220.0]  210.00  306.75   96.75   98.98   1 System
[MARASH29 220.0]  208.00  290.00   82.00   99.28   1 System
[HRAZDN49 400.0]  430.00  512.00   82.00   99.32   1 System
[HRZDNSS3 220.0]  218.00  290.00   72.00   99.48   1 System
[HRZDNPP1 220.0]  440.00  508.00   68.00   99.40   1 System
[GYUMRI13 220.0]    5.50   73.50   68.00   87.71   1 System
[YERVNP41 110.0]    5.50   65.50   60.00   86.65   1 System
[SHAHMN21 220.0]    5.50   65.50   60.00   87.94   1 System
[ALVRDI11 220.0]    5.50   63.50   58.00   93.08   1 System
[HRAZDN49 400.0]    5.50   61.50   56.00   88.50   1 System
[MARASH29 220.0]    5.50   61.50   56.00   90.33   1 System
[VANDZOR7 220.0]    5.50   61.50   56.00   89.74   1 System
[HRZDNPP1 220.0]    5.50   59.50   54.00   88.54   1 System
[HRZDNSS3 220.0]    5.50   59.50   54.00   88.52   1 System
------ Load bus relative voltage dip below     0.0% for entire system -------
Bus  name           start    end   elapsed    vlo%     area
cycles  cycles  cycles
[AMNPP_18 220.0]  168.00  600.00  432.00   97.31   1 System
[TAVRZ_50 400.0]  188.00  343.25  155.25   97.87   1 System
[YERVNP30 110.0]  184.00  318.50  134.50   98.88   1 System
[AGARAK38 220.0]  370.00  500.00  130.00   99.39   1 System
[TAVRZ_50 400.0]    5.50  131.75  126.25   87.71   1 System
[MXCHAN47 110.0]  188.00  307.75  119.75   99.01   1 System
[AGARAK38 220.0]  140.00  250.00  110.00   98.61   1 System
[AMNPP_18 220.0]    5.50  111.50  106.00   86.21   1 System
[ASHNAK16 110.0]    5.50  105.50  100.00   86.46   1 System
[ARARAT31 110.0]  194.00  288.00   94.00   99.49   1 System
[GYUMRI14 110.0]    5.50   73.50   68.00   87.64   1 System
[AMNPP_17 110.0]    5.50   65.50   60.00   87.02   1 System
[SHAHMN20 110.0]    5.50   65.50   60.00   86.78   1 System
[ECHMDZ19 110.0]    5.50   65.50   60.00   86.71   1 System
[HAGHTK45 220.0]    5.50   65.50   60.00   88.02   1 System
[YERAVN42   6.0]    5.50   65.50   60.00   86.50   1 System
[YERVNP30 110.0]  446.00  494.00   48.00   99.91   1 System
[GAVAR_40 220.0]    5.50   53.50   48.00   89.94   1 System
[ARARAT31 110.0]    5.50   53.50   48.00   94.48   1 System
[VANDZOR8 110.0]    5.50   51.50   46.00   90.89   1 System
```

Scenario-3-a   3


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
200.0
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario-3-a
4


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
GENERATOR POWER MW
CYCLES
Scenario-3-a
5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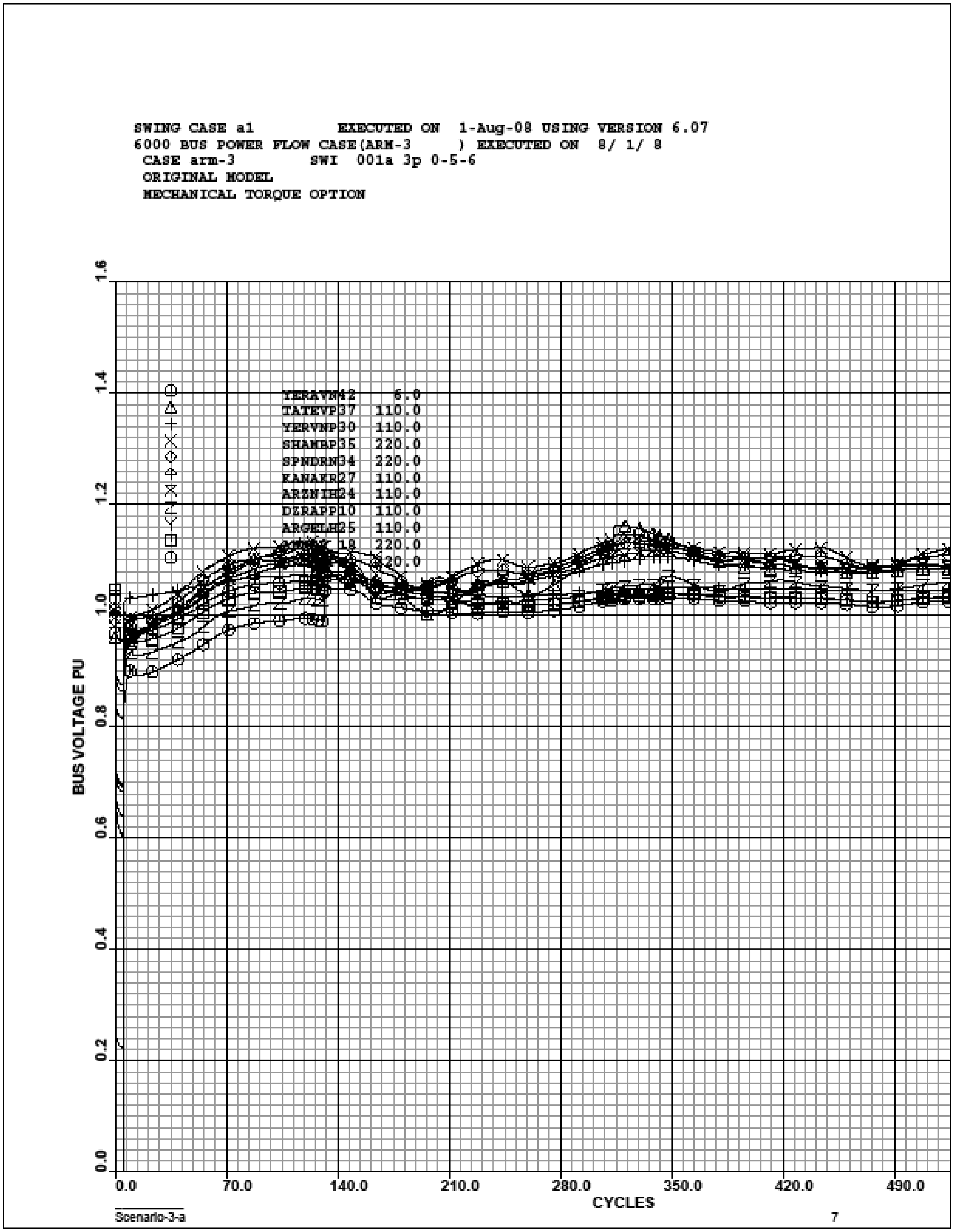
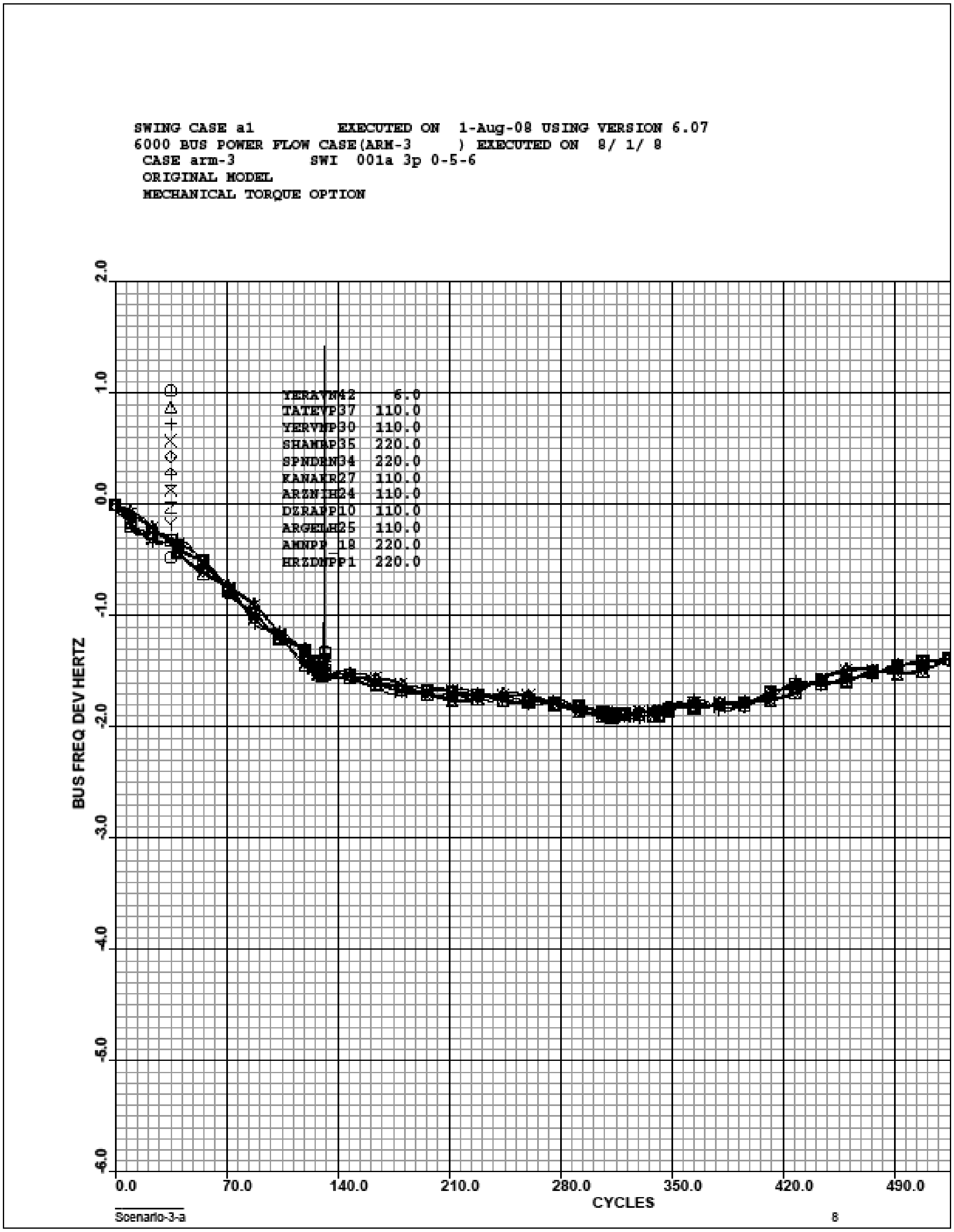
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
-2000.0
-3000.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario-3-a
6


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
SHAMBP35 220.0
SPNDRN34 220.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
ARGELH25 110.0
BUS VOLTAGE PU
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario-3-a
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVM42 6.0
TATEVP37 110.0
YERVNP30 110.0
SHAMAP35 220.0
SPNDRN34 220.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
ARGELH25 110.0
AMNPP_18 220.0
HRZDNPP1 220.0
BUS FREQ DEV HERTZ
2.0
1.0
0.0
-1.0
-2.0
-3.0
-4.0
-5.0
-6.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario-3-a
8

1.7 APPENDIX 4.3.B

Scenario 3. 2030 Winter MAX
Short circuit on bus-bar of HVL-400 kV Tabriz with tripping HVL
Disconnection of ANPP

```
SWING CASE a1         EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  8/ 1/ 8
CASE arm-3        SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3      8  1  1
F1                     1
LS  HRAZDN49 400  TAVRZ_50 400 1    2    0.0
LS -HRAZDN49 400 -TAVRZ_50 400 1   -2    5.5
LS  AMNPP_18 2201                   4    11.5                      9
FF      .25 0600.                                50      0   1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES                              THE
FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
```

BUS NAME	BASE KV	VOLTAGE(PU)	RELATIVE %	TIME(CYCLES)
HRZDNPP5	110.0	0.7718	85.18	5.50
SEVANPP6	110.0	0.7791	85.98	5.50
N	220.0	0.7884	83.20	5.50
HRZDNPP4	10.0	0.7884	83.20	5.50
HRZDNCP2	110.0	0.7896	86.84	5.50
TAVRZ_50	400.0	0.8002	72.29	5.50
HRZDNPP1	220.0	0.8185	79.38	5.50
GYUMRI14	110.0	0.8205	86.25	5.50
HRAZDN49	400.0	0.8210	79.49	5.50
HRZDNSS3	220.0	0.8228	80.33	5.50
ECHMDZ19	110.0	0.8306	87.24	5.50
ALVRD12	110.0	0.8309	87.05	5.50
DZRAPP10	110.0	0.8373	86.40	5.50
YERAVN42	6.0	0.8398	86.68	5.50
YERVNP41	110.0	0.8400	86.74	5.50
SHAHMN20	110.0	0.8401	86.80	5.50
VANDZOR7	220.0	0.8404	83.30	5.50
VANDZOR8	110.0	0.8418	85.83	5.50
VANDZOR9	110.0	0.8421	85.87	5.50
LICHK_44	110.0	0.8470	85.70	5.50

THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES

BUS NAME	BASE KV	VOLTAGE(PU)	RELATIVE %	TIME(CYCLES)
TATEVP37	110.0	1.1912	124.04	322.75
SHAMBP35	220.0	1.1692	115.78	324.50
TAVRZ_50	400.0	1.1638	105.14	140.50
ARGELH25	110.0	1.1574	117.83	327.75
SPNDRN34	220.0	1.1510	113.49	325.75
CHRNCV26	110.0	1.1426	118.67	327.75
SHNHYR36	220.0	1.1381	113.49	324.50
ARZNIH24	110.0	1.1346	113.83	329.75
ZOVUNI23	110.0	1.1229	112.20	331.75
KANAKR27	110.0	1.1191	111.59	331.75
YEGHDZ33	220.0	1.1170	109.91	327.75
YEGHDZ43	110.0	1.1138	111.21	327.75
HRZDNCP2	110.0	1.1107	122.17	331.75
SEVANPP6	110.0	1.1083	122.33	331.75
SPITK_48	110.0	1.1021	112.45	331.75
HRZDNPP5	110.0	1.0992	121.32	333.75
HRAZDN49	400.0	1.0916	105.69	140.50
LICHK_39	220.0	1.0913	107.52	138.50
GAVAR_40	220.0	1.0910	106.92	138.50
HRZDNPP1	220.0	1.0909	105.81	140.50

THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES
DURING NONFAULT PERIODS.

Scenario 3-b 1

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
HRZDNPP1	220.0	-2.3083	320.25
HRAZDN49	400.0	-2.3082	320.25
TAVRZ_50	400.0	-2.3078	320.25
HRZDNSS3	220.0	-2.3073	320.25
YERAVN42	6.0	-2.3039	321.00
AMNPP_51	400.0	-2.3037	320.25
YERVNP41	110.0	-2.3036	321.00
AMNPP_18	220.0	-2.3035	320.25
SHAHMN20	110.0	-2.3032	321.00
ECHMDZ19	110.0	-2.3029	321.00
SHAHMN21	220.0	-2.3027	320.50
ZOVUNI22	220.0	-2.3026	321.00
AMNPP_17	110.0	-2.3025	321.00
HAGHTK45	220.0	-2.3023	320.50
ASHNAK15	220.0	-2.3022	320.25
HRZDNPP4	10.0	-2.3022	321.00
N	220.0	-2.3022	321.00
ASHNAK16	110.0	-2.3021	320.50
ARGELH25	110.0	-2.3005	321.25
GAVAR_40	220.0	-2.3004	317.50

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
YEGHDZ33	220.0		2.8026	327.75
ARZNIH24	110.0	1	2.3616	321.75
KANAKR27	110.0	1	2.3568	320.50
YERAVN42	6.0	1	2.3531	325.25
SEVANPP6	110.0	1	2.3297	282.50
ARGELH25	110.0	1	2.3199	322.50
HRZDNPP1	220.0	1	2.3185	319.50
TATEVP37	110.0	1	2.3102	317.50
SPNDRN34	220.0	1	2.3078	309.00
AGARAK38	220.0	1	2.2936	308.00
SHAMBP35	220.0	1	2.2870	302.50
YERVNP30	110.0	1	2.2829	308.00
DZRAPP10	110.0	1	2.2596	322.75
TBILIS46	220.0	1	2.2359	333.75
AMNPP_18	220.0	1	0.2265	5.50

The following 20 generators have the highest field voltage deviations

GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
AMNPP_18	220.0	1	2.9898	2.00
SEVANPP6	110.0	1	2.4770	331.75
ARGELH25	110.0	1	2.4543	327.75
SHAMBP35	220.0	1	2.3747	324.50
TATEVP37	110.0	1	2.2045	323.25
DZRAPP10	110.0	1	2.1506	331.75
KANAKR27	110.0	1	2.0715	331.75
SPNDRN34	220.0	1	2.0396	325.25
ARZNIH24	110.0	1	1.9923	329.75
YERAVN42	6.0	1	1.0522	329.75
HRZDNPP1	220.0	1	0.8396	57.50
YERVNP30	110.0	1	0.2923	172.50
AGARAK38	220.0	1	0.1630	144.50

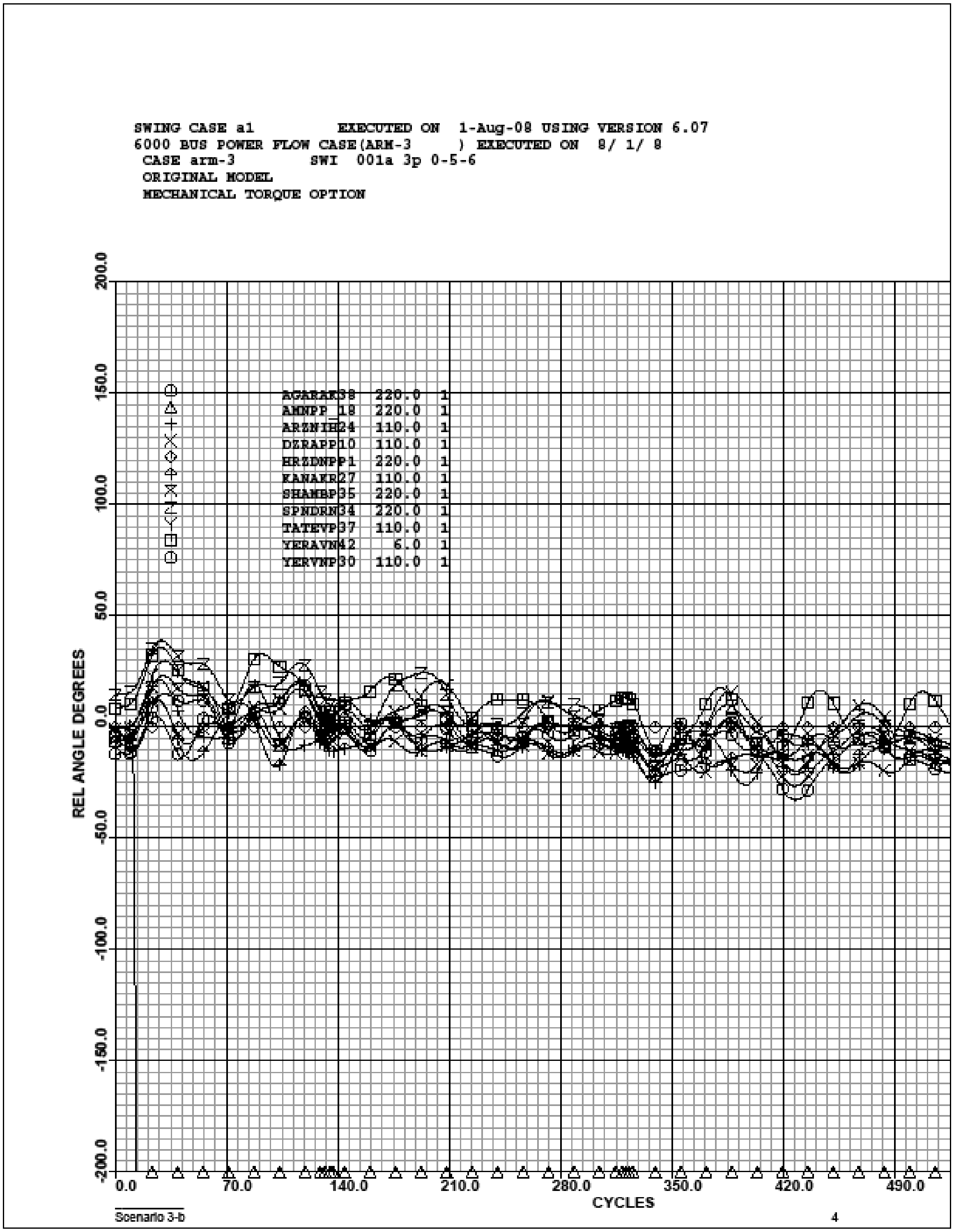
THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
AMNPP_18	220.0	1	0.0500	9.50
ARGELH25	110.0	1	0.0500	9.50
DZRAPP10	110.0	1	0.0500	39.50
KANAKR27	110.0	1	0.0500	43.50
ARZNIH24	110.0	1	0.0500	47.50
YERAVN42	6.0	1	0.0500	121.50
SEVANPP6	110.0	1	0.0500	127.25
SHAMBP35	220.0	1	0.0500	150.50
TATEVP37	110.0	1	0.0500	172.50

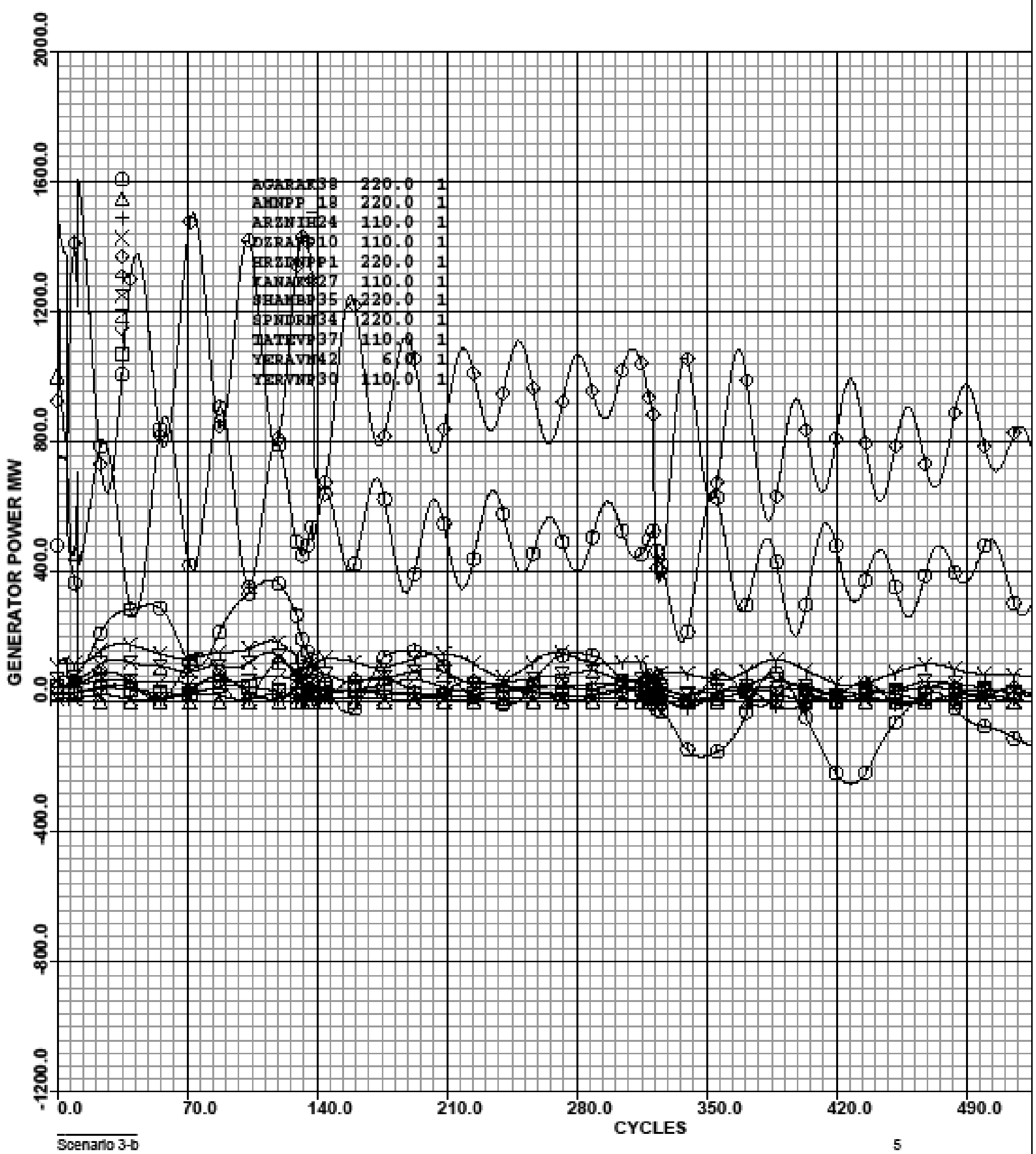
Scenario 3-b 2

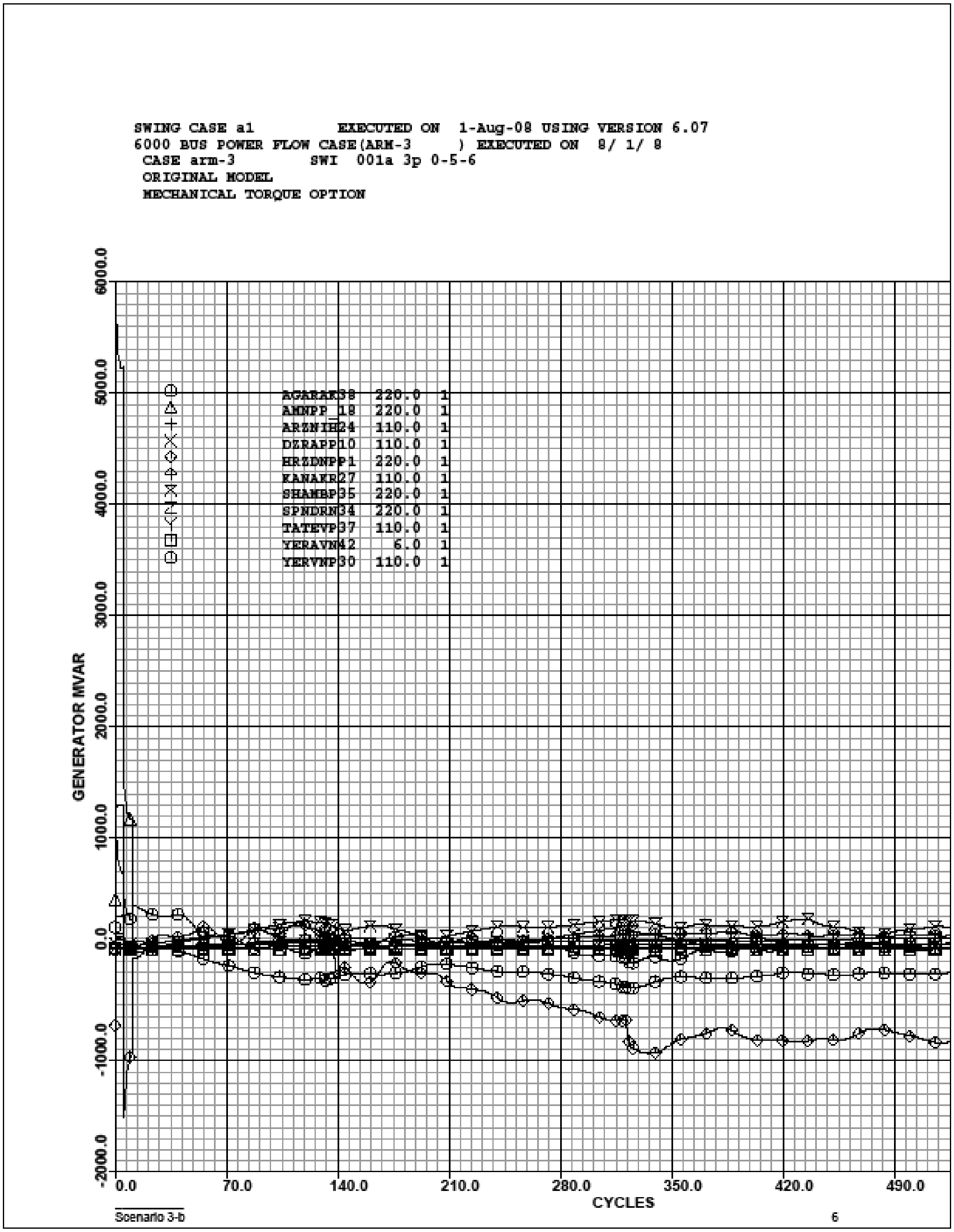
```
*******************************************************************
****                                                          ****
****                         VFHIST                           ****
****                                                          ****
****      GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT    ****
****                                                          ****
****          TIME INTERVAL =     0.0 TO   597.8 CYCLES       ****
****                                                          ****
****                                                          ****
**** BASE CASE TITLE:                                         ****
**** ARM-3                                                    ****
**** a1                                                       ****
****                                                          ****
*******************************************************************
------ No-load bus relative voltage dip below     0.0% For entire system -----
-        Bus  name            start    end  elapsed    VLO%     area
cycles  cycles  cycles
[AMNPP_51 400.0]  367.75  600.00  232.25   98.45   1 System
[AMNPP_51 400.0]  176.50  322.25  145.75   97.12   1 System
[ASHNAK15 220.0]  188.50  319.00  130.50   98.10   1 System
[HRAZDN49 400.0]  208.50  316.50  108.00   98.59   1 System
[HRZDNPP1 220.0]  210.50  313.00  102.50   98.69   1 System
[HRAZDN49 400.0]  417.75  511.75   94.00   99.03   1 System
[MARASH29 220.0]  200.50  294.50   94.00   98.95   1 System
[HRZDNPP1 220.0]  421.75  509.75   88.00   99.10   1 System
[HRZDNSS3 220.0]  218.50  294.50   76.00   99.21   1 System
[AMNPP_51 400.0]    5.50   79.50   74.00   88.09   1 System
[ASHNAK15 220.0]    5.50   77.50   72.00   88.43   1 System
[GYUMRI13 220.0]    5.50   71.50   66.00   86.32   1 System
[TBILIS46 220.0]  347.75  411.75   64.00   96.42   1 System
[TBILIS46 220.0]  449.75  513.75   64.00   96.19   1 System
[ALVRDI11 220.0]    5.50   67.50   62.00   88.76   1 System
[SHAHMN21 220.0]    5.50   67.50   62.00   86.49   1 System
[YERVNP41 110.0]    5.50   67.50   62.00   86.74   1 System
[SHAHMN21 220.0]  218.50  278.50   60.00   99.74   1 System
[ARARAT32 220.0]    5.50   63.50   58.00   89.40   1 System
[VANDZOR7 220.0]    5.50   63.50   58.00   83.30   1 System
------ Load bus relative voltage dip below     0.0% for entire system -------
Bus  name            start    end  elapsed    vlo%     area
cycles  cycles  cycles
[AMNPP_18 220.0]  367.75  600.00  232.25   98.44   1 System
[AMNPP_18 220.0]  174.50  322.25  147.75   97.08   1 System
[YERVNP30 110.0]  182.50  319.00  136.50   98.72   1 System
[TAVRZ_50 400.0]    5.50  138.00  132.50   72.29   1 System
[AGARAK38 220.0]  361.75  489.75  128.00   99.20   1 System
[TAVRZ_50 400.0]  194.50  321.50  127.00   97.55   1 System
[MXCHAN47 110.0]  186.50  309.00  122.50   98.86   1 System
[AGARAK38 220.0]  150.50  256.50  106.00   98.59   1 System
[ARARAT31 110.0]  190.50  286.50   96.00   99.30   1 System
[YERVNP30 110.0]  425.75  503.75   78.00   99.87   1 System
[AMNPP_18 220.0]    5.50   81.50   76.00   88.03   1 System
[ASHNAK16 110.0]    5.50   77.50   72.00   88.32   1 System
[GYUMRI14 110.0]    5.50   71.50   66.00   86.25   1 System
[ECHMDZ19 110.0]    5.50   67.50   62.00   87.24   1 System
[AMNPP_17 110.0]    5.50   67.50   62.00   88.53   1 System
[SHAHMN20 110.0]    5.50   67.50   62.00   86.80   1 System
[YERAVN42   6.0]    5.50   67.50   62.00   86.68   1 System
[HAGHTK45 220.0]    5.50   67.50   62.00   86.61   1 System
[HAGHTK45 220.0]  218.50  276.50   58.00   99.76   1 System
[LICHK_44 110.0]    5.50   59.50   54.00   85.70   1 System
```

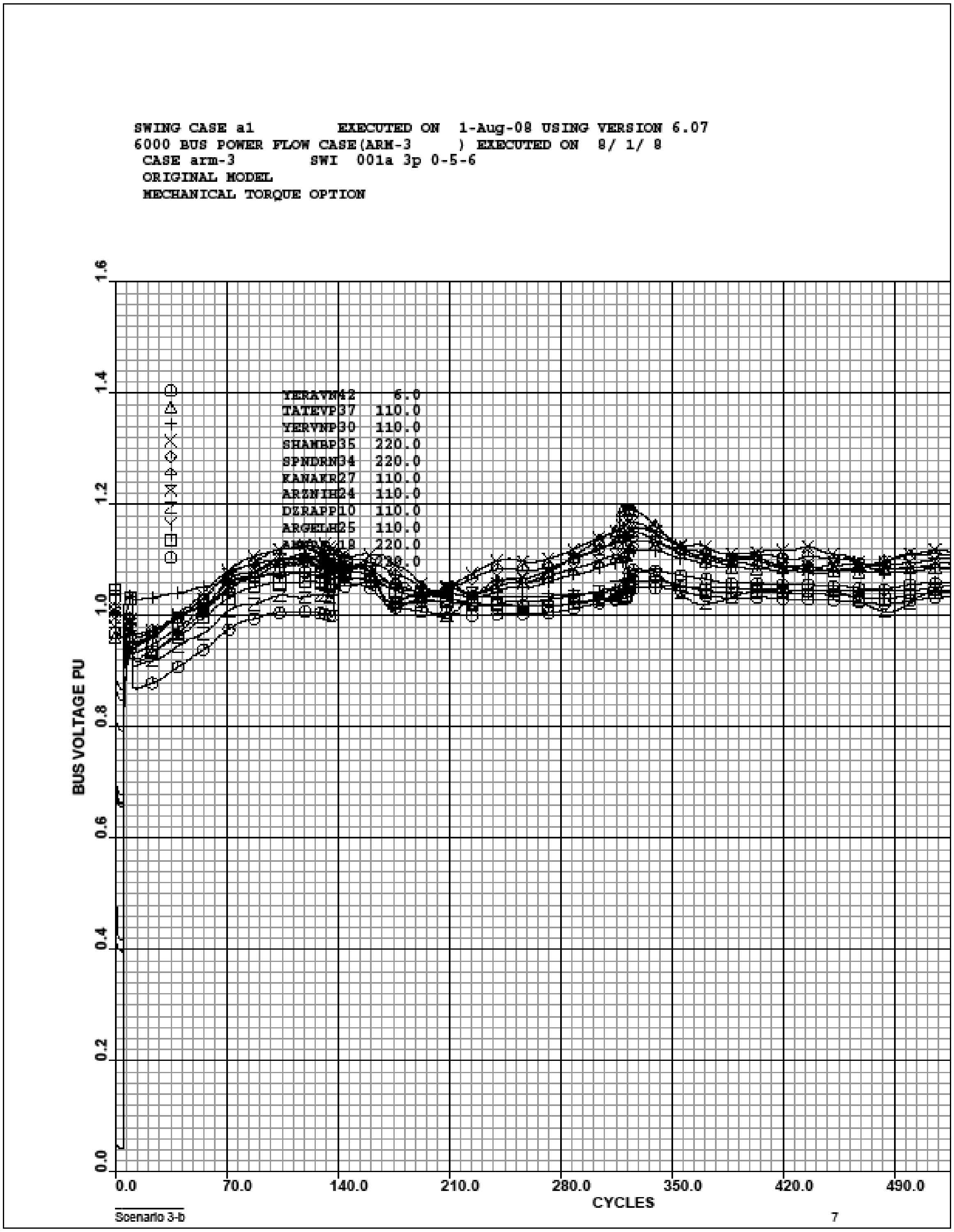
Scenario 3-b 3

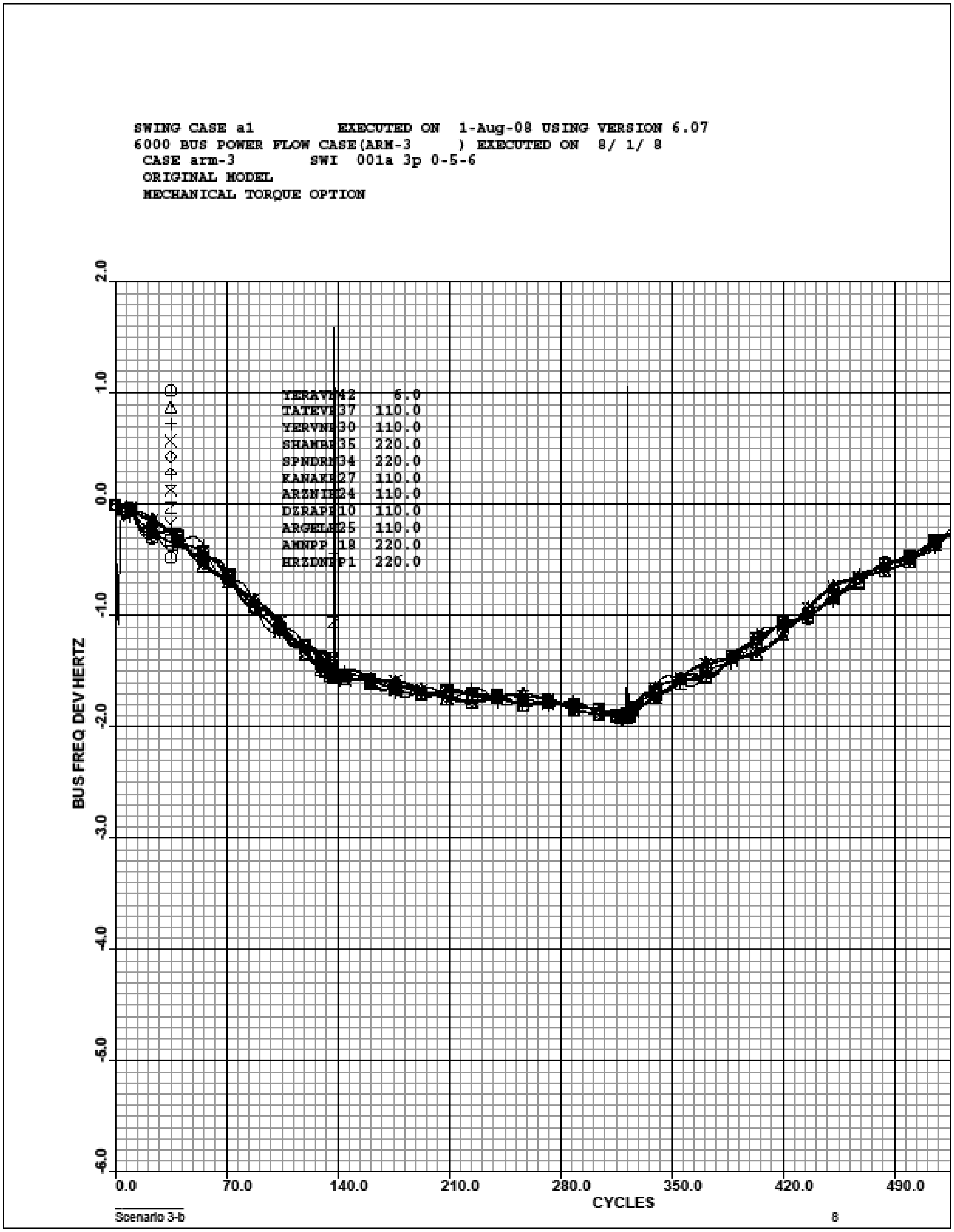

SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
200.0
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 3-b
4

```
SWING CASE a1         EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  8/ 1/ 8
 CASE arm-3        SWI  001a 3p 0-5-6
 ORIGINAL MODEL
 MECHANICAL TORQUE OPTION
```




SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AGARAK38 220.0 1
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
SHAMBP35 220.0 1
SPNDRN34 220.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
6000.0
5000.0
4000.0
3000.0
2000.0
1000.0
0.0
-1000.0
-2000.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 3-b
6


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
SHAMBP35 220.0
SPNDRN34 220.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
ARGELH25 110.0
BUS VOLTAGE PU
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 3-b
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN 42 6.0
TATEV 37 110.0
YERVN 30 110.0
SHAMB 35 220.0
SPNDR 34 220.0
KANAK 27 110.0
ARZNI 24 110.0
DZRAP 10 110.0
ARGEL 25 110.0
ANNPP 18 220.0
HRZDN P1 220.0
BUS FREQ DEV HERTZ
CYCLES
Scenario 3-b

1.8 APPENDIX 4.4.A

```
Scenario 4.       2030 Summer MIN
                  Short circuit on ANPP's bus-bar with tripping ANPP
                  Disconnection of HVL-400 kV Tabriz

SWING CASE a1         EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3     ) EXECUTED ON  8/ 1/ 8
CASE arm-3        SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3      8  1  1
F1                   1
LS  AMNPP_18 220  ARARAT32 220 1    2    0.0
LS  AMNPP_18 220  ARARAT32 220 1   -2    5.5
LS  AMNPP_18 2201                   4    5.5                          9
LS -HRAZDN49 400 -TAVRZ_50 400 1         11.5
FF      .25 0600.                                  50       0   1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES
THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
TAVRZ_50   400.0      0.8207       77.09        13.50
ECHMDZ19   110.0      0.8807       88.46         5.50
YERAVN42     6.0      0.8874       88.52         5.50
YERVNP41   110.0      0.8877       88.56         5.50
SHAHMN20   110.0      0.8880       88.60         5.50
ASHNAK16   110.0      0.9000       88.10         5.50
AMNPP_17   110.0      0.9002       88.37         5.50
HRZDNPP5   110.0      0.9133       90.82         5.50
N          220.0      0.9154       90.19         5.50
HRZDNPP4    10.0      0.9155       90.20         5.50
HRZDNPP1   220.0      0.9173       88.97         5.50
HRZDNSS3   220.0      0.9182       89.07         5.50
HRAZDN49   400.0      0.9183       88.95         5.50
SEVANPP6   110.0      0.9202       91.28         5.50
GYUMRI14   110.0      0.9211       88.97         5.50
HRZDNCP2   110.0      0.9236       91.58         5.50
ASHNAK15   220.0      0.9237       88.12         5.50
SHAHMN21   220.0      0.9238       89.11         5.50
AMNPP_51   400.0      0.9238       87.85         5.50
AMNPP_18   220.0      0.9239       87.82         5.50
THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES
BUS NAME  BASE KV  VOLTAGE(PU)  RELATIVE %  TIME(CYCLES)
N          220.0      2.7469      270.66       359.25
HRZDNPP4    10.0      2.7462      270.58       359.25
HRZDNPP5   110.0      2.3266      231.35       359.25
SEVANPP6   110.0      2.1580      214.08       359.25
HRZDNCP2   110.0      2.0218      200.47       359.25
CHRNCV26   110.0      1.3886      136.51       347.25
TATEVP37   110.0      1.2671      128.44       337.25
TAVRZ_50   400.0      1.2481      117.23       194.25
ARGELH25   110.0      1.2454      121.97       347.25
HRZDNSS3   220.0      1.2401      120.30       144.50
SPITK_48   110.0      1.2075      117.47       347.25
SHAMBP35   220.0      1.2014      117.12       337.25
VANDZOR9   110.0      1.1984      116.39       359.25
VANDZOR8   110.0      1.1981      116.36       359.25
DZRAPP10   110.0      1.1953      115.83       244.25
ARZNIH24   110.0      1.1874      115.86       349.25
SPNDRN34   220.0      1.1755      114.58       337.25
SHNHYR36   220.0      1.1711      115.01       337.25
ZOVUNI23   110.0      1.1679      113.92       349.25
ALVRD12    110.0      1.1651      112.85       242.25
```

Scenario 4-a   1

THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES
DURING NONFAULT PERIODS.

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
HRZDNPP4	10.0	-3.8983	293.00
N	220.0	-3.8972	293.00
HRZDNPP5	110.0	-3.8721	293.00
SEVANPP6	110.0	-3.8643	293.00
HRZDNCP2	110.0	-3.8371	293.00
CHRNCV26	110.0	-3.6922	293.00
YERVNP30	110.0	-3.6566	289.00
MXCHAN47	110.0	-3.6346	289.00
ARGELH25	110.0	-3.6340	293.00
SPITK_48	110.0	-3.6099	329.25
VANDZOR9	110.0	-3.6031	329.25
VANDZOR8	110.0	-3.6029	329.25
HRZDNSS3	220.0	-3.6025	331.25
HRZDNPP1	220.0	-3.5966	333.25
HRAZDN49	400.0	-3.5962	333.25
TAVRZ_50	400.0	-3.5950	333.25
ARZNIH24	110.0	-3.5938	329.25
MARASH28	110.0	-3.5854	292.25
DZRAPP10	110.0	-3.5851	329.25
ZOVUNI23	110.0	-3.5823	329.25

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
SEVANPP6	110.0	1	5.2466	214.50
KANAKR27	110.0	1	4.3333	271.75
DZRAPP10	110.0	1	4.2466	224.50
HRZDNPP4	10.0	1	4.0406	292.25
YERAVN42	6.0	1	3.9141	349.25
ARGELH25	110.0	1	3.8299	286.25
YERVNP30	110.0	1	3.7113	287.00
HRZDNPP1	220.0	1	3.6851	335.25
YEGHDZ33	220.0		3.6504	292.25
ARZNIH24	110.0	1	3.6098	345.25
TATEVP37	110.0	1	3.5615	296.00
TBILIS46	220.0	1	3.5515	299.25
SPNDRN34	220.0	1	3.5444	299.25
SHAMBP35	220.0	1	3.5194	287.00
AGARAK38	220.0	1	3.5071	296.00
AMNPP_18	220.0	1	0.0235	2.00

The following 20 generators have the highest field voltage deviations

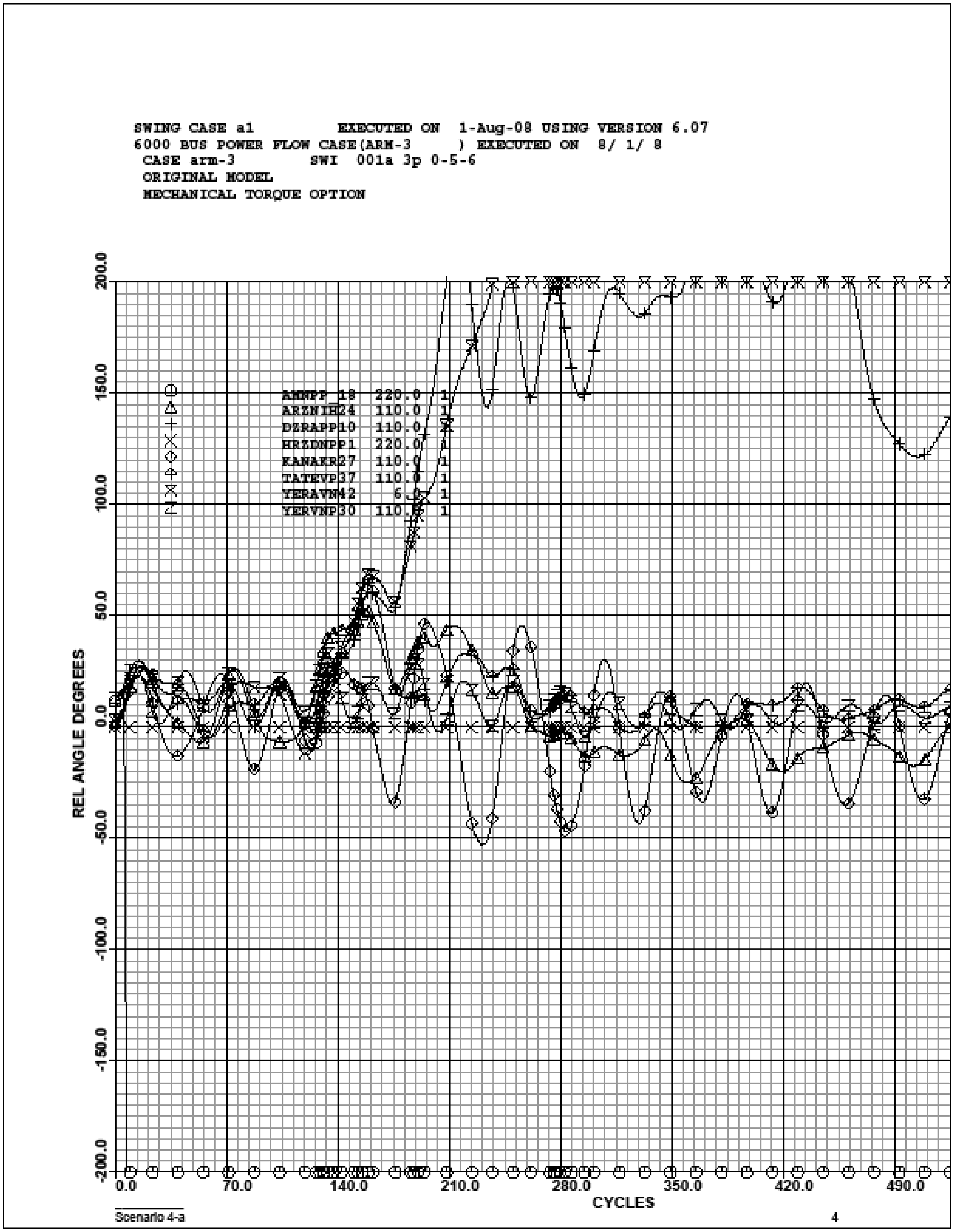
GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
SEVANPP6	110.0	1	5.3821	323.25
HRZDNPP4	10.0	1	5.2613	319.25
AMNPP_18	220.0	1	3.0564	2.00
TATEVP37	110.0	1	2.7130	337.25
ARGELH25	110.0	1	2.6706	347.25
SPNDRN34	220.0	1	2.4435	337.25
SHAMBP35	220.0	1	2.4394	337.25
DZRAPP10	110.0	1	2.3843	244.25
KANAKR27	110.0	1	2.3039	349.25
ARZNIH24	110.0	1	2.2733	349.25
YERAVN42	6.0	1	1.7313	131.25
HRZDNPP1	220.0	1	1.1841	220.50
YERVNP30	110.0	1	0.2976	188.00
AGARAK38	220.0	1	0.2170	357.25

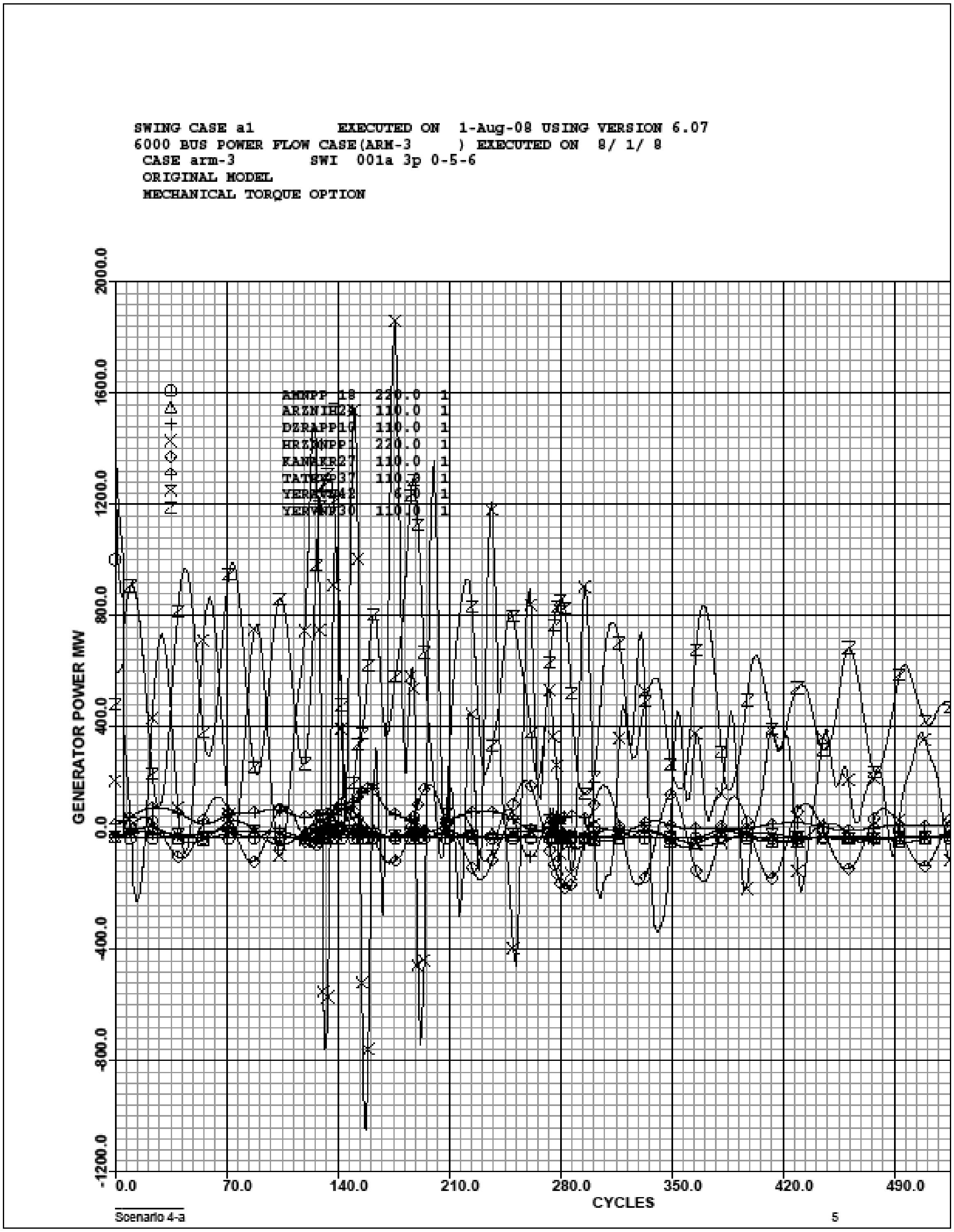
THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

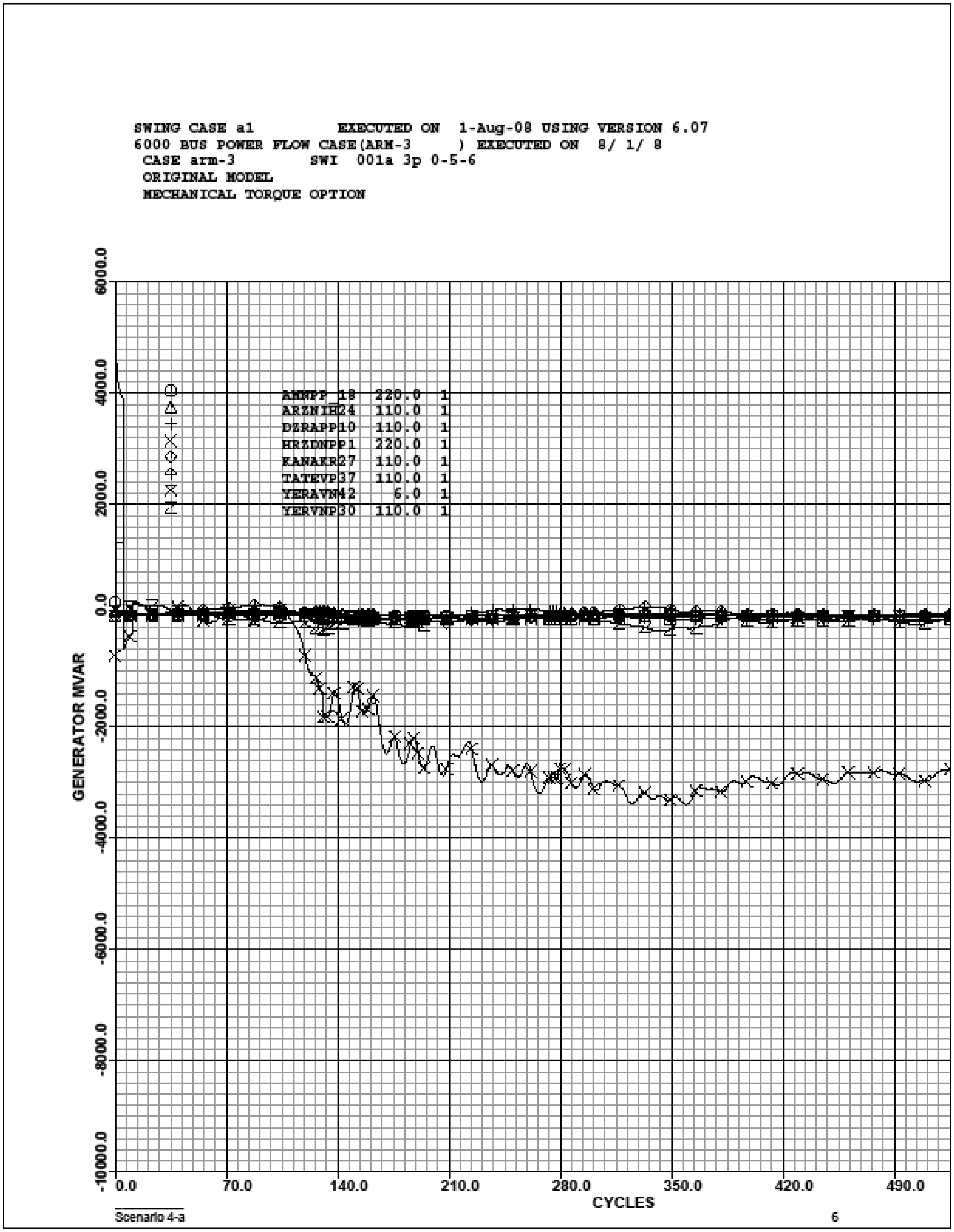
GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
ARGELH25	110.0	1	0.0500	23.50
DZRAPP10	110.0	1	0.0500	27.50
KANAKR27	110.0	1	0.0500	31.50
ARZNIH24	110.0	1	0.0500	37.50
SEVANPP6	110.0	1	0.0500	51.50

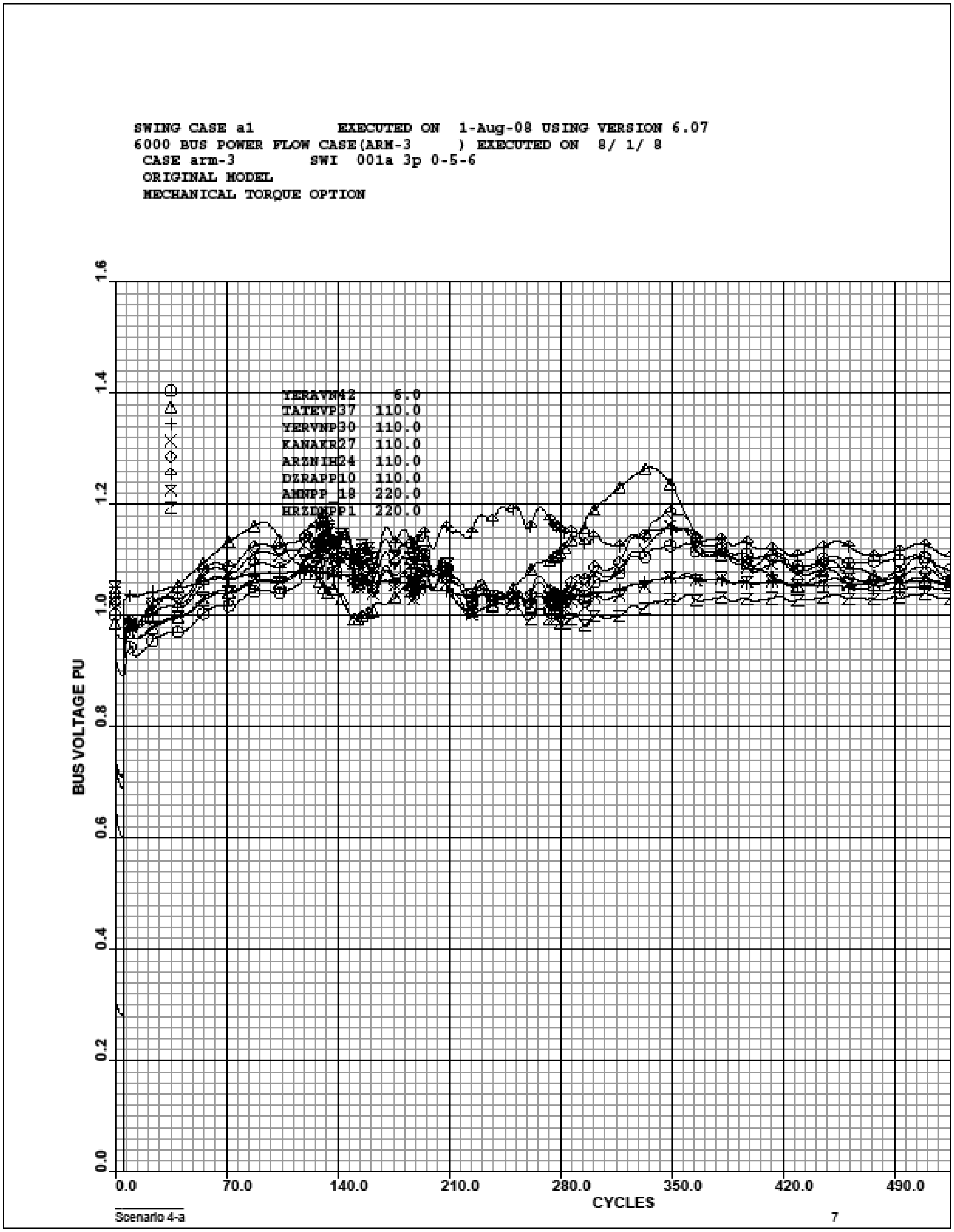
Scenario 4-a 2

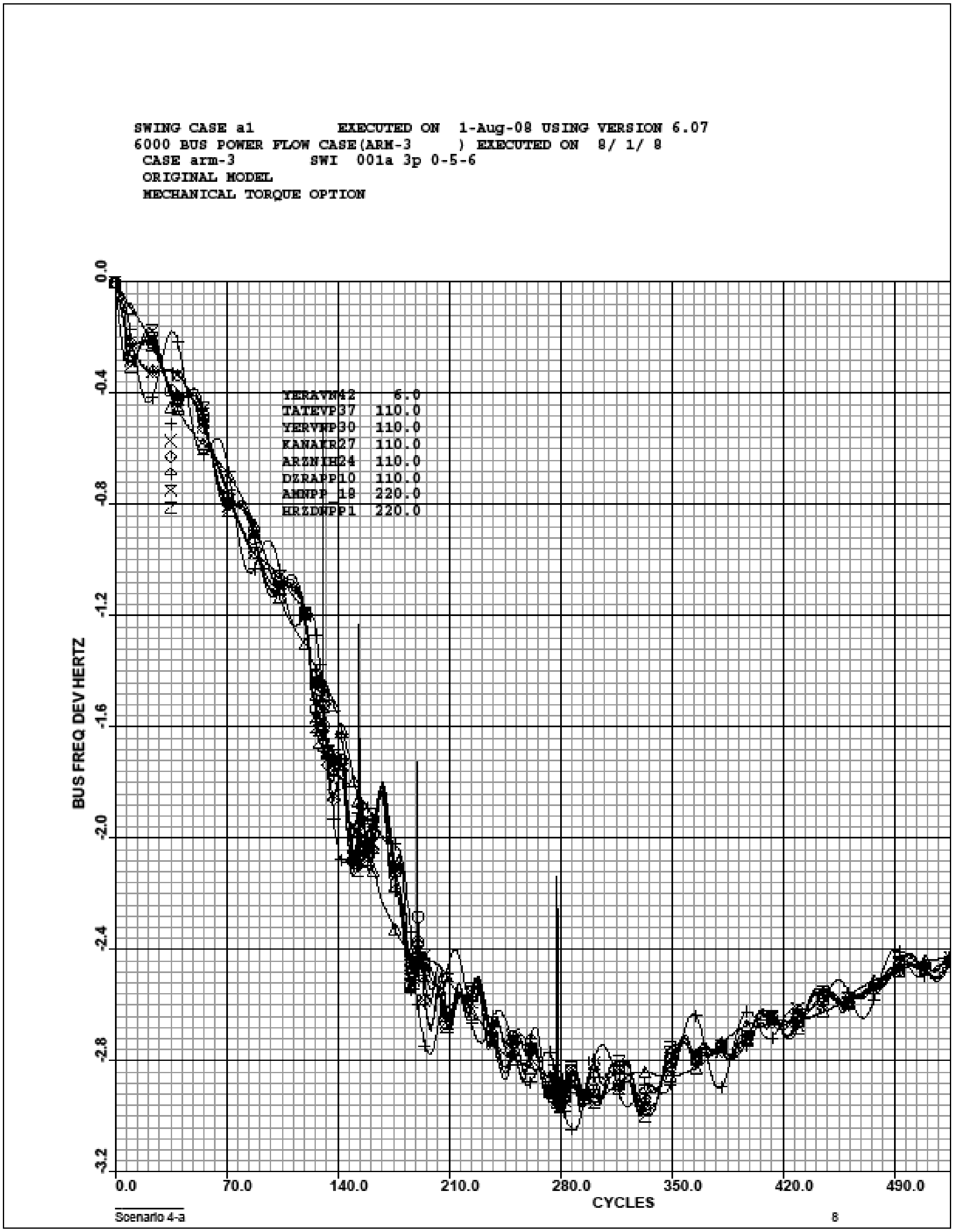
```
YERAVN42     6.0   1    0.0500         51.50
SHAMBP35   220.0   1    0.0500        170.25
TATEVP37   110.0   1    0.0500        176.75
**********************************************************************
****                                                              ****
****                           VFHIST                             ****
****                                                              ****
****       GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT       ****
****                                                              ****
****            TIME INTERVAL =     0.0 TO   597.2 CYCLES         ****
****                                                              ****
****                                                              ****
**** BASE CASE TITLE:                                             ****
**** ARM-3                                                        ****
**** a1                                                           ****
****                                                              ****
**********************************************************************
------ No-load bus relative voltage dip below     0.0% For entire system -----
-        Bus  name            start    end  elapsed    VLO%     area
cycles  cycles  cycles
[HRAZDN49 400.0]  234.50  355.25  120.75   95.25   1 System
[HRZDNPP1 220.0]  234.50  355.25  120.75   95.27   1 System
[AMNPP_51 400.0]  234.50  321.25   86.75   96.34   1 System
[MARASH29 220.0]  234.50  321.25   86.75   96.90   1 System
[AMNPP_51 400.0]    0.00   77.50   77.50   87.85   1 System
[ASHNAK15 220.0]    0.00   77.50   77.50   88.12   1 System
[ASHNAK15 220.0]  244.25  319.25   75.00   97.25   1 System
[N        220.0]    0.00   73.50   73.50   90.17   1 System
[HRZDNPP4  10.0]    0.00   73.50   73.50   90.19   1 System
[GYUMRI13 220.0]    0.00   61.50   61.50   88.97   1 System
[HRAZDN49 400.0]    0.00   57.50   57.50   88.95   1 System
[VANDZOR7 220.0]    0.00   55.50   55.50   90.22   1 System
[SHAHMN21 220.0]    0.00   55.50   55.50   89.11   1 System
[HRZDNPP1 220.0]    0.00   55.50   55.50   88.97   1 System
[HRZDNSS3 220.0]    0.00   55.50   55.50   89.07   1 System
[ALVRDI11 220.0]    0.00   55.50   55.50   93.39   1 System
[MARASH29 220.0]    0.00   53.50   53.50   90.88   1 System
[YERVNP41 110.0]    0.00   53.50   53.50   88.56   1 System
[ZOVUNI22 220.0]    0.00   51.50   51.50   89.98   1 System
[ARARAT32 220.0]    0.00   51.50   51.50   90.92   1 System
------ Load bus relative voltage dip below     0.0% for entire system -------
Bus  name            start    end  elapsed    vlo%     area
cycles  cycles  cycles
[TAVRZ_50 400.0]    0.00  130.50  130.50   77.09   1 System
[AGARAK38 220.0]  361.25  487.25  126.00   98.52   1 System
[YERVNP30 110.0]  198.50  321.25  122.75   97.85   1 System
[MXCHAN47 110.0]  200.50  317.25  116.75   98.01   1 System
[AGARAK38 220.0]  124.00  237.25  113.25   98.21   1 System
[YERVNP30 110.0]  459.25  553.25   94.00   99.32   1 System
[AMNPP_18 220.0]  234.50  321.25   86.75   96.39   1 System
[ASHNAK16 110.0]    0.00   77.50   77.50   88.10   1 System
[AMNPP_18 220.0]    0.00   77.50   77.50   87.82   1 System
[ARARAT31 110.0]  232.50  299.25   66.75   98.45   1 System
[GYUMRI14 110.0]    0.00   61.50   61.50   88.96   1 System
[AMNPP_17 110.0]    0.00   55.50   55.50   88.37   1 System
[ECHMDZ19 110.0]    0.00   55.50   55.50   88.46   1 System
[HAGHTK45 220.0]    0.00   55.50   55.50   89.18   1 System
[SHAHMN20 110.0]    0.00   53.50   53.50   88.60   1 System
[YERAVN42   6.0]    0.00   53.50   53.50   88.52   1 System
[VANDZOR8 110.0]    0.00   49.50   49.50   91.10   1 System
[HRZDNPP5 110.0]    0.00   49.50   49.50   90.81   1 System
[ARARAT31 110.0]    0.00   49.50   49.50   94.68   1 System
[GAVAR_40 220.0]    0.00   49.50   49.50   90.50   1 System
```


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
200.0
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-a
4


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
GENERATOR POWER MW
2000.0
1600.0
1200.0
800.0
400.0
0.0
-400.0
-800.0
-1200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-a
5


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
6000.0
4000.0
2000.0
0.0
-2000.0
-4000.0
-6000.0
-8000.0
-10000.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-a
6


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
AHNPP_18 220.0
HRZDNPP1 220.0
BUS VOLTAGE PU
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-a
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
AMNPP_18 220.0
HRZDNPP1 220.0
BUS FREQ DEV HERTZ
0.0
-0.4
-0.8
-1.2
-1.6
-2.0
-2.4
-2.8
-3.2
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-a
8

1.9 APPENDIX 4.4.B

<u>Scenario 4.</u> 2030 Summer MIN
Short circuit on bus-bar of HVL-400 kV Tabriz with tripping HVL
Disconnection of ANPP

```
SWING CASE a1          EXECUTED ON  1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3      ) EXECUTED ON  8/ 1/ 8
CASE arm-3        SWI  001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
CASE arm-3      8  1  1
F1                  1
LS  HRAZDN49 400  TAVRZ_50 400 1    2    0.0
LS -HRAZDN49 400 -TAVRZ_50 400 1   -2    5.5
LS  AMNPP_18 2201                   4    11.5                          9
FF      .25 0600.                                  50       0   1     1
LOW BUS VOLTAGES WERE NOT CALCULATED
DURING THE FOLLOWING FAULT PERIODS.
0.000 CYCLES TO    5.500 CYCLES
THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS VOLTAGES
DURING NONFAULT PERIODS.
```

BUS NAME	BASE KV	VOLTAGE(PU)	RELATIVE %	TIME(CYCLES)
TAVRZ_50	400.0	0.6235	58.56	5.50
HRZDNPP1	220.0	0.8091	78.48	5.50
HRAZDN49	400.0	0.8106	78.51	5.50
HRZDNSS3	220.0	0.8204	79.58	5.50
N	220.0	0.8396	82.73	5.50
HRZDNPP4	10.0	0.8397	82.73	5.50
HRZDNPP5	110.0	0.8543	84.95	5.50
GAVAR_40	220.0	0.8559	82.97	5.50
VANDZOR7	220.0	0.8574	82.84	5.50
SEVANPP6	110.0	0.8659	85.90	5.50
ECHMDZ19	110.0	0.8736	87.75	5.50
HRZDNCP2	110.0	0.8745	86.71	5.50
SHAHMN20	110.0	0.8752	87.33	5.50
YERVNP41	110.0	0.8756	87.36	5.50
YERAVN42	6.0	0.8761	87.39	5.50
LICHK_44	110.0	0.8780	85.41	5.50
VANDZOR8	110.0	0.8802	85.49	5.50
VANDZOR9	110.0	0.8806	85.53	5.50
LICHK_39	220.0	0.8820	85.41	5.50
ZOVUNI22	220.0	0.8868	85.75	5.50

THE FOLLOWING 20 BUSES HAVE THE HIGHEST BUS VOLTAGES

BUS NAME	BASE KV	VOLTAGE(PU)	RELATIVE %	TIME(CYCLES)
N	220.0	2.7586	271.80	347.75
HRZDNPP4	10.0	2.7581	271.75	347.75
HRZDNPP5	110.0	2.3447	233.15	347.75
SEVANPP6	110.0	2.1767	215.94	347.75
HRZDNCP2	110.0	2.0426	202.53	347.75
CHRNCV26	110.0	1.4103	138.63	347.75
ARGELH25	110.0	1.2592	123.32	349.75
TATEVP37	110.0	1.2549	127.20	339.75
TAVRZ_50	400.0	1.2475	117.17	218.00
HRZDNSS3	220.0	1.2381	120.10	169.00
SPITK_48	110.0	1.2126	117.97	349.75
VANDZOR9	110.0	1.1981	116.36	349.75
SHAMBP35	220.0	1.1976	116.75	347.75
VANDZOR8	110.0	1.1976	116.31	349.75
ARZNIH24	110.0	1.1868	115.81	347.75
DZRAPP10	110.0	1.1783	114.17	256.50
SPNDRN34	220.0	1.1724	114.28	347.75
SHNHYR36	220.0	1.1658	114.49	345.75
ZOVUNI23	110.0	1.1633	113.47	347.75
ALVRD12	110.0	1.1558	111.96	256.50

Scenario 4-b 1

THE FOLLOWING 20 BUSES HAVE THE LOWEST BUS FREQUENCIES
DURING NONFAULT PERIODS.

BUS NAME	BASE KV	FREQUENCY(HERTZ)	TIME(CYCLES)
HRZDNPP4	10.0	-3.9225	317.75
N	220.0	-3.9215	317.75
HRZDNPP5	110.0	-3.8849	317.75
SEVANPP6	110.0	-3.8660	317.75
HRZDNCP2	110.0	-3.8436	317.75
CHRNCV26	110.0	-3.6909	317.75
ARGELH25	110.0	-3.6304	317.75
SPITK_48	110.0	-3.6066	317.75
VANDZOR9	110.0	-3.6000	317.75
VANDZOR8	110.0	-3.5997	317.75
DZRAPP10	110.0	-3.5892	317.75
HRZDNPP1	220.0	-3.5850	327.75
HRAZDN49	400.0	-3.5845	327.75
TAVRZ_50	400.0	-3.5843	327.75
HRZDNSS3	220.0	-3.5832	327.75
ALVRD12	110.0	-3.5778	317.75
VANDZOR7	220.0	-3.5644	327.75
ARZNIH24	110.0	-3.5634	317.75
GYUMRI13	220.0	-3.5622	327.75
GYUMRI14	110.0	-3.5622	327.75

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST FREQUENCY DEVIATIONS

GEN NAME	BASE KV	ID	frequency(hertz)	time(cycles)
SEVANPP6	110.0	1	4.7816	261.25
DZRAPP10	110.0	1	4.2666	276.25
KANAKR27	110.0	1	4.1149	345.75
HRZDNPP4	10.0	1	4.1008	221.00
YERAVN42	6.0	1	3.9558	357.75
YEGHDZ33	220.0		3.8513	313.75
ARGELH25	110.0	1	3.7836	305.75
ARZNIH24	110.0	1	3.6721	303.75
HRZDNPP1	220.0	1	3.6717	323.75
YERVNP30	110.0	1	3.6000	309.75
TBILIS46	220.0	1	3.5645	311.75
SHAMBP35	220.0	1	3.5428	303.75
SPNDRN34	220.0	1	3.5371	311.75
AGARAK38	220.0	1	3.5238	302.00
TATEVP37	110.0	1	3.5197	309.75
AMNPP_18	220.0	1	0.2690	11.50

The following 20 generators have the highest field voltage deviations

GEN NAME	BASE KV	ID	FIELD VLT DEV	TIME(CYCLES)
SEVANPP6	110.0	1	5.2882	325.75
HRZDNPP4	10.0	1	5.1728	319.75
AMNPP_18	220.0	1	3.0564	2.00
ARGELH25	110.0	1	2.7133	349.75
TATEVP37	110.0	1	2.6751	339.75
SPNDRN34	220.0	1	2.4339	347.75
SHAMBP35	220.0	1	2.4276	347.75
DZRAPP10	110.0	1	2.3315	256.50
KANAKR27	110.0	1	2.2813	347.75
ARZNIH24	110.0	1	2.2717	347.75
YERAVN42	6.0	1	1.6989	157.25
HRZDNPP1	220.0	1	1.1787	242.50
YERVNP30	110.0	1	0.2765	177.50
AGARAK38	220.0	1	0.2105	361.75

THE FOLLOWING 20 GENERATORS HAVE THE HIGHEST PSS OUTPUT DEVIATIONS

GEN NAME	BASE KV	ID	PSS OUT DEV	TIME(CYCLES)
DZRAPP10	110.0	1	0.0500	43.50
ARGELH25	110.0	1	0.0500	47.50
KANAKR27	110.0	1	0.0500	49.50
ARZNIH24	110.0	1	0.0500	55.50
SEVANPP6	110.0	1	0.0500	123.50

```
YERAVN42     6.0   1    0.0500         123.50
TATEVP37   110.0   1    0.0500         154.25
SHAMBP35   220.0   1    0.0500         196.00
AMNPP_18   220.0   1    0.0080           4.00
**********************************************************************
****                                                              ****
****                           VFHIST                             ****
****                                                              ****
****       GLOBAL BUS VOLTAGE AND FREQUENCY SCANNING REPORT       ****
****                                                              ****
****            TIME INTERVAL =     0.0 TO   597.8 CYCLES         ****
****                                                              ****
****                                                              ****
**** BASE CASE TITLE:                                             ****
**** ARM-3                                                        ****
**** a1                                                           ****
****                                                              ****
**********************************************************************
------ No-load bus relative voltage dip below     0.0% For entire system -----
-        Bus  name            start    end  elapsed    VLO%     area
cycles  cycles  cycles
[HRZDNPP1 220.0]  260.50  435.75  175.25   95.68   1 System
[HRAZDN49 400.0]  260.50  435.75  175.25   95.65   1 System
[AMNPP_51 400.0]  258.50  343.75   85.25   96.47   1 System
[ASHNAK15 220.0]    0.00   71.50   71.50   88.32   1 System
[AMNPP_51 400.0]    0.00   71.50   71.50   88.74   1 System
[ALVRDI11 220.0]    0.00   69.50   69.50   88.58   1 System
[GYUMRI13 220.0]    0.00   69.50   69.50   86.11   1 System
[HRZDNPP4  10.0]    0.00   67.50   67.50   82.72   1 System
[N        220.0]    0.00   67.50   67.50   82.71   1 System
[MARASH29 220.0]  258.50  325.75   67.25   97.28   1 System
[VANDZOR7 220.0]    0.00   65.50   65.50   82.84   1 System
[SHAHMN21 220.0]    0.00   63.50   63.50   86.32   1 System
[HRZDNSS3 220.0]    0.00   63.50   63.50   79.58   1 System
[HRAZDN49 400.0]    0.00   63.50   63.50   78.51   1 System
[ASHNAK15 220.0]  260.50  323.75   63.25   97.31   1 System
[HRZDNPP1 220.0]    0.00   61.50   61.50   78.48   1 System
[MARASH29 220.0]    0.00   61.50   61.50   87.73   1 System
[YERVNP41 110.0]    0.00   59.50   59.50   87.36   1 System
[ZOVUNI22 220.0]    0.00   55.50   55.50   85.75   1 System
[ARARAT32 220.0]    0.00   55.50   55.50   89.33   1 System
------ Load bus relative voltage dip below     0.0% for entire system -------
Bus  name            start    end  elapsed    vlo%     area
cycles  cycles  cycles
[TAVRZ_50 400.0]    0.00  151.25  151.25   58.56   1 System
[AGARAK38 220.0]  365.75  489.75  124.00   98.71   1 System
[YERVNP30 110.0]  200.00  323.75  123.75   97.89   1 System
[AGARAK38 220.0]  119.50  226.50  107.00   98.25   1 System
[MXCHAN47 110.0]  222.50  321.75   99.25   97.97   1 System
[AMNPP_18 220.0]  258.50  341.75   83.25   96.51   1 System
[YERVNP30 110.0]  497.75  579.75   82.00   99.33   1 System
[AMNPP_18 220.0]    0.00   71.50   71.50   89.14   1 System
[ASHNAK16 110.0]    0.00   71.50   71.50   88.30   1 System
[GYUMRI14 110.0]    0.00   69.50   69.50   86.11   1 System
[HAGHTK45 220.0]    0.00   63.50   63.50   86.44   1 System
[AMNPP_17 110.0]    0.00   63.50   63.50   88.77   1 System
[ECHMDZ19 110.0]    0.00   61.50   61.50   87.75   1 System
[SHAHMN20 110.0]    0.00   61.50   61.50   87.33   1 System
[YERAVN42   6.0]    0.00   59.50   59.50   87.39   1 System
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[ARARAT31 110.0]    0.00   51.50   51.50   94.07   1 System
[ARARAT31 110.0]  256.50  307.75   51.25   98.40   1 System
[VANDZOR8 110.0]    0.00   49.50   49.50   85.49   1 System
[LICHK_44 110.0]    0.00   49.50   49.50   85.41   1 System
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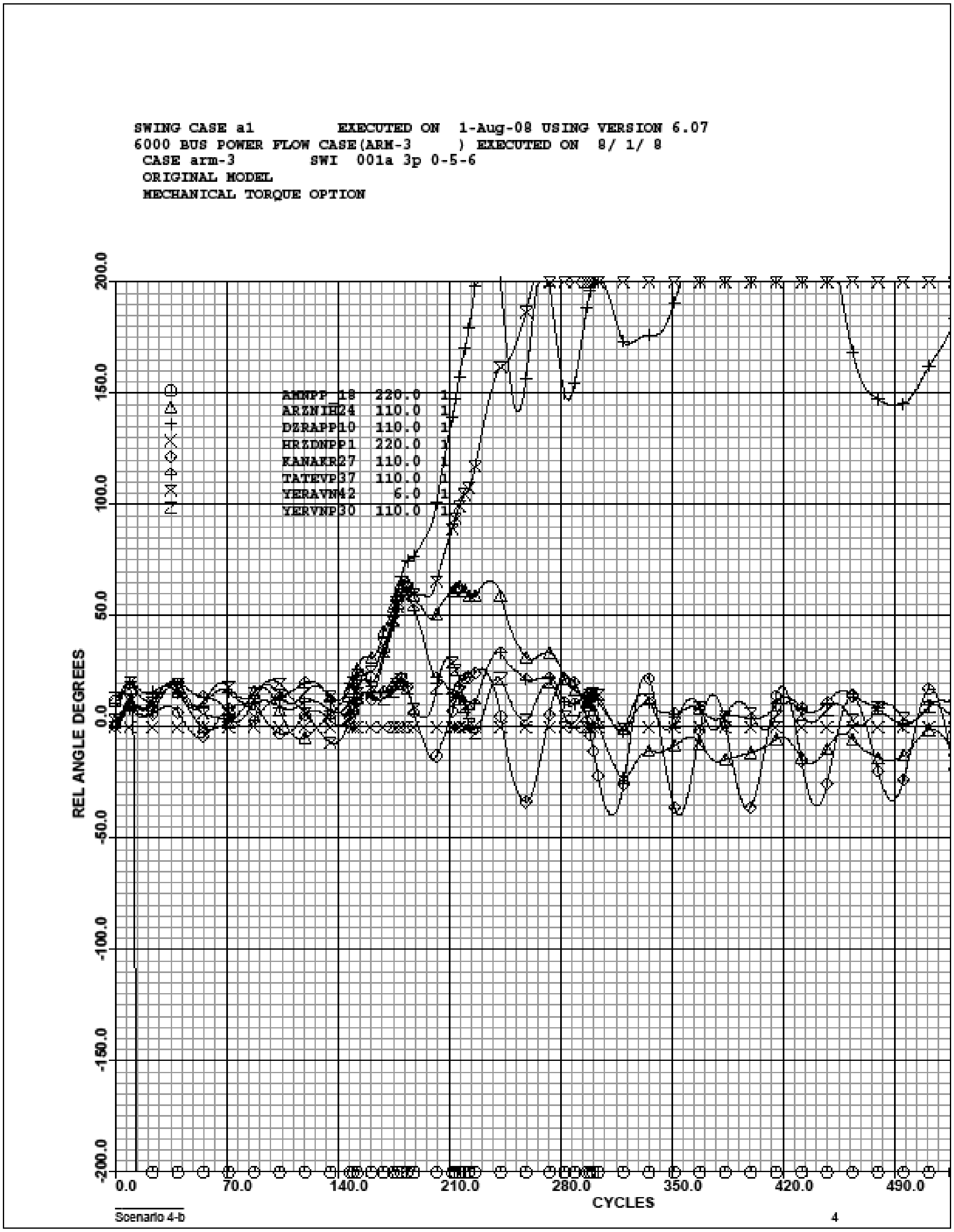
Scenario 4-b   3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6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
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ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
REL ANGLE DEGREES
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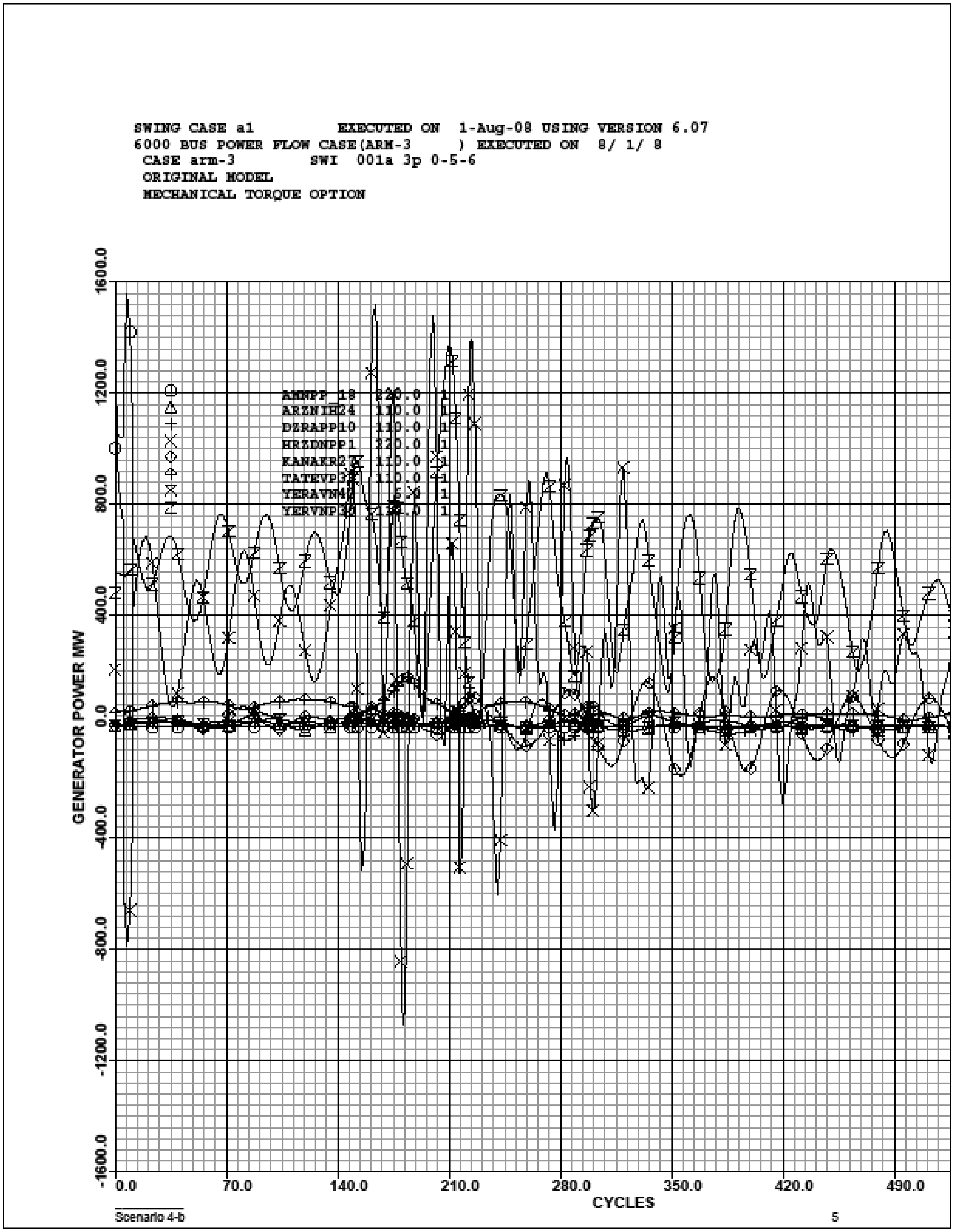
150.0
100.0
50.0
0.0
-50.0
-100.0
-150.0
-200.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-b
4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CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
GENERATOR POWER MW
1600.0
1200.0
800.0
400.0
0.0
-400.0
-800.0
-1200.0
-1600.0
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140.0
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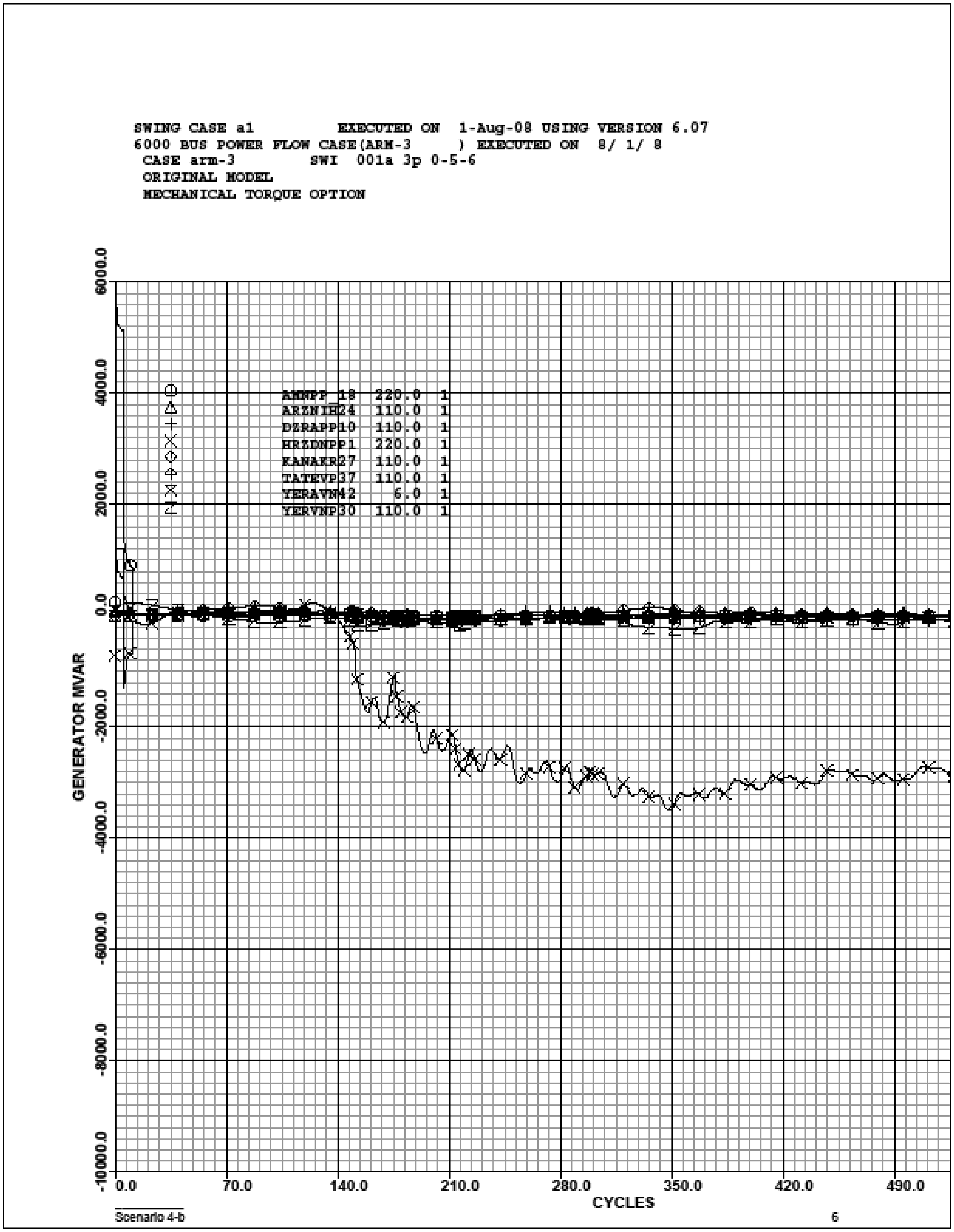
350.0
420.0
490.0
CYCLES
Scenario 4-b
5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CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
AMNPP_18 220.0 1
ARZNIH24 110.0 1
DZRAPP10 110.0 1
HRZDNPP1 220.0 1
KANAKR27 110.0 1
TATEVP37 110.0 1
YERAVN42 6.0 1
YERVNP30 110.0 1
GENERATOR MVAR
6000.0
4000.0
2000.0
0.0
-2000.0
-4000.0
-6000.0
-8000.0
-10000.0
0.0
70.0
140.0
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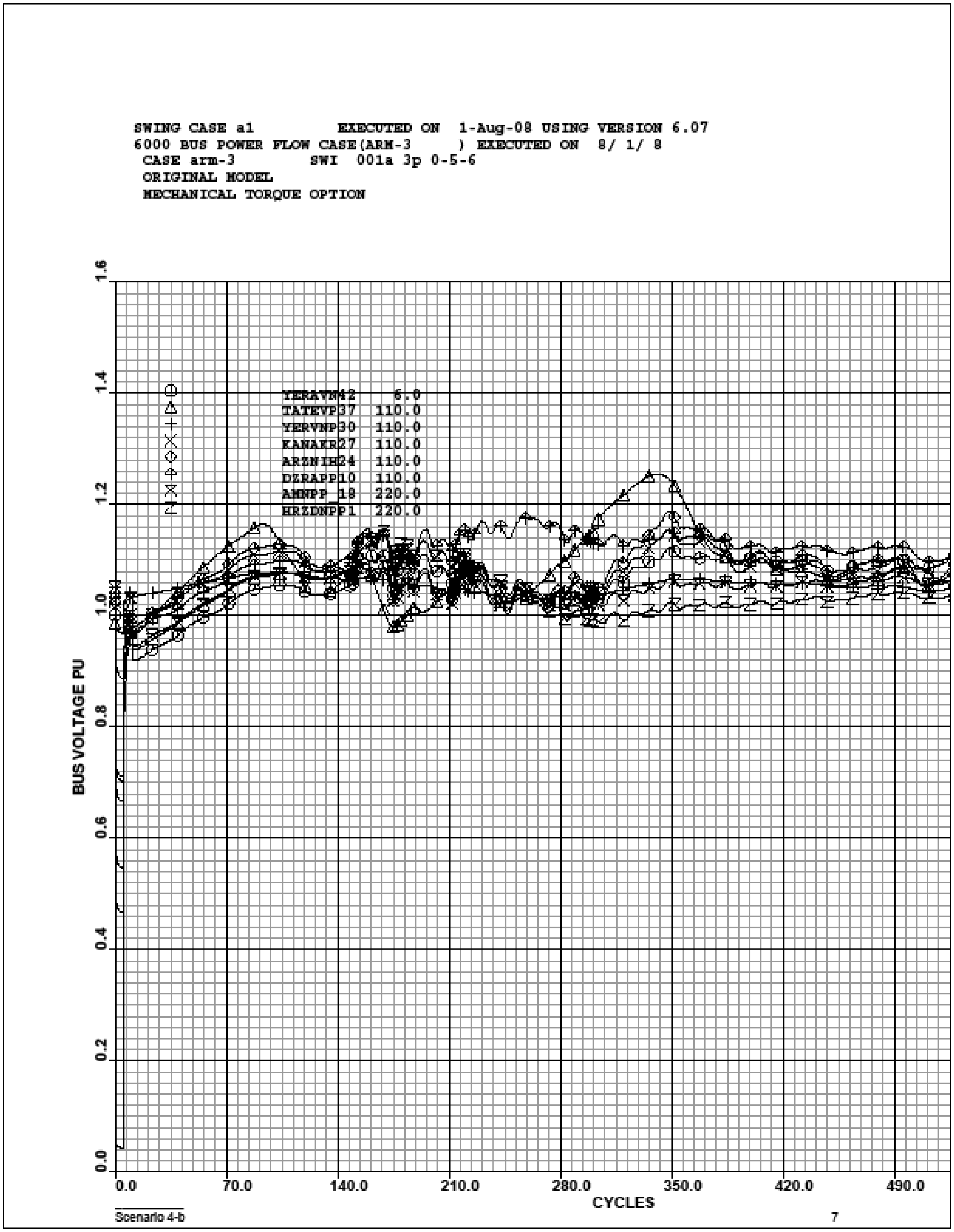
350.0
420.0
490.0
CYCLES
Scenario 4-b
6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CASE arm-3   SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
AMNPP_18 220.0
HRZDNPP1 220.0
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0.6
0.8
1.0
1.2
1.4
1.6
0.0
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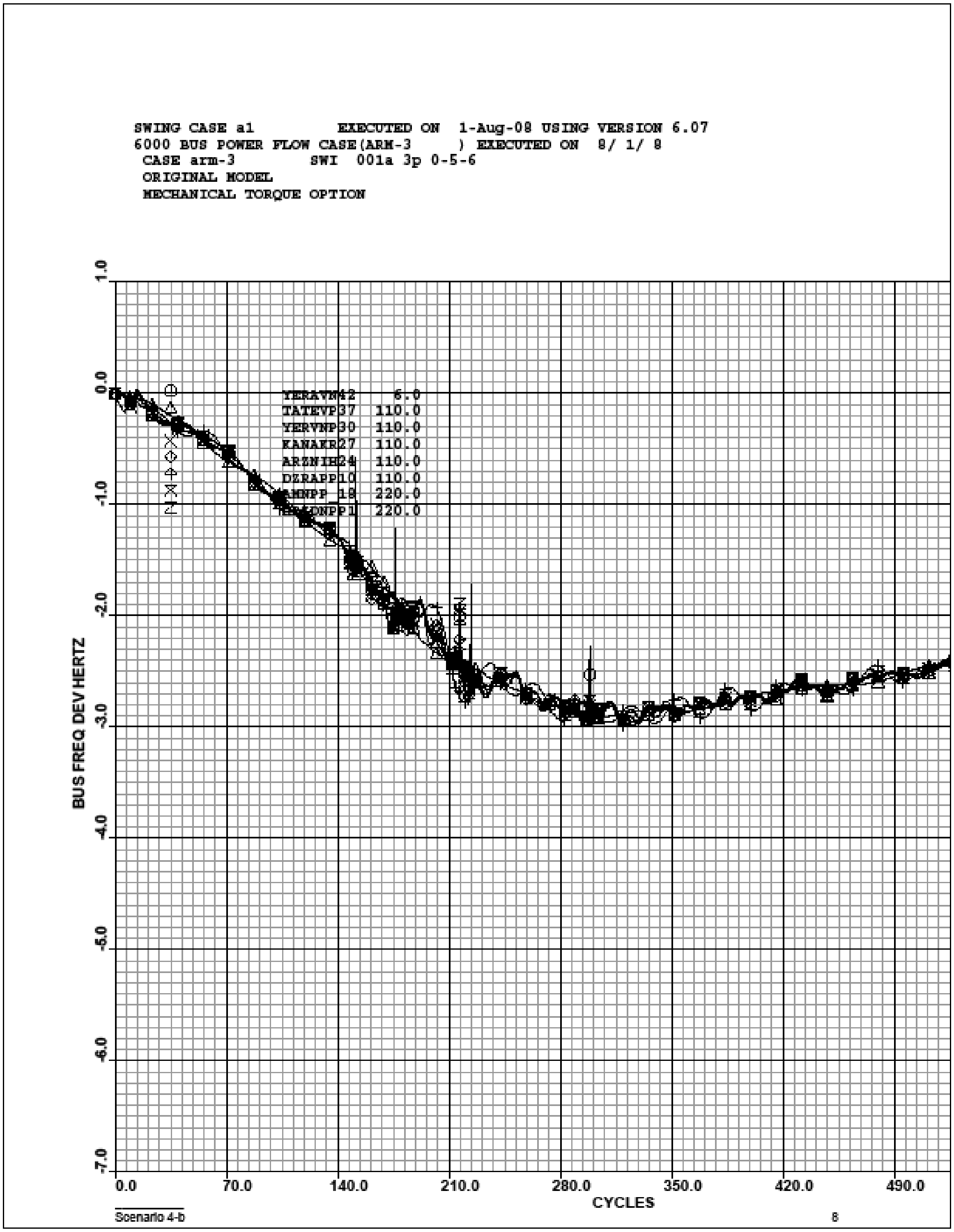
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-b
7


SWING CASE a1 EXECUTED ON 1-Aug-08 USING VERSION 6.07
6000 BUS POWER FLOW CASE(ARM-3) EXECUTED ON 8/ 1/ 8
CASE arm-3 SWI 001a 3p 0-5-6
ORIGINAL MODEL
MECHANICAL TORQUE OPTION
YERAVN42 6.0
TATEVP37 110.0
YERVNP30 110.0
KANAKR27 110.0
ARZNIH24 110.0
DZRAPP10 110.0
AMNPP 18 220.0
220.0
BUS FREQ DEV HERTZ
1.0
0.0
-1.0
-2.0
-3.0
-4.0
-5.0
-6.0
-7.0
0.0
70.0
140.0
210.0
280.0
350.0
420.0
490.0
CYCLES
Scenario 4-b
8

APPENDIX A TO CHAPTER 6: KEY ISSUES RAISED BY FINANCIAL INSTITUTIONS

The following section highlights the key issues that were raised in our discussions with potential lenders to the Project:

US Export-Import Bank

- Ex-Im Bank does not have a limit on the funds it could lend to the Project.
- However, they would need the IMF to consent to the level of financing.
- Armenia is risk category 6 on a 1-7 scale, with 7 being the riskiest.
- The exposure fee for 100% cover with a 7 year repayment period is in the range of 10-11%.

Export Development Canada (EDC)

- EDC has a limited appetite for projects in Armenia, since Armenia is rated quite low on their country scale. As such, EDC would be able to provide "no where near the total sought."
- However, if the Project were to take on national importance, then EDC support in some form could be discussed. In order for that to happen, AECL would have to submit a definitive request to EDC. Any discussion prior to that would be purely hypothetical.
- In any case the Armenian government engagement in the Project would have to be “enormous," involving everything from initial environmental studies through decommissioning

European Bank for Reconstruction and Development (EBRD)

- EBRD did not rule out the possibility of involvement in the Project, but they felt it would be particularly difficult to finance the Project on both political and commercial grounds.
- EBRD is the only multilateral institution that is allowed to finance nuclear projects under its policy, but EBRD has not financed a greenfield nuclear project to date.
- It would be difficult for EBRD to gather the political support for the Project as several of its member states are opposed to developing nuclear energy.
- Funding would be limited to €250 million.
- There is no adjustment on the cost of borrowing based on Armenia’s credit rating since EBRD offers the same interest rate to all of its borrowers (1.0% above EBRD’s own cost of funds).
- The loan tenor would be in the range of 15-18 years.
- A sovereign guarantee would be required.
- There remains a concern that Armenia would not have the revenue to pay off its debt obligation because cost overruns are typical in the case of nuclear projects.

European Atomic Energy Community (Euratom)

- Euratom cannot take part in funding a new nuclear project, but can assist in decommissioning or safety improvements of existing plants. This could free up funds that could be used towards a new plant.
- Euratom can finance decommissioning at up to 50% of the overall cost.

- Euratom's total borrowing limit is €600 million, which they intend to spread amongst several projects.
- The amount that Euratom would be willing to lend to GoA would depend on GoA's ability to provide sovereign guarantees.
- Possibility of a joint loan with EBRD.
- Euratom representatives will be in Yerevan for meetings on September 11-12, which may present a good opportunity to speak with them further.

AIG

- Major Concerns:

  1. The government licensing and permitting process for construction of the plant and the government's role in streamlining the process.

  2. How interest during construction will be handled due to the long construction period of nuclear. They felt a $2-3 billion estimate was not fully accounting for IDC.
- Sovereign Guarantee: This is not an absolute requirement. Particularly if the reactor is government-owned, they felt the guarantee would be meaningless.
- Decommissioning: These costs must be factored in on the front end.
- Insurance: AIG offers an insurance policy that caps the cost of decommissioning. They also offer insurance for cost overrun risk for an experienced EPC contractor. They indicated few insurance companies would offer insurance for reactor or fuel risk.
- Interest Rate: They would offer market based interest rates with no penalty for nuclear. Specific rates would depend on structuring of the deal, technology being used, offtakers, tariff rates, EPC contractor, etc.
- Technology risk: The Candu 6 reactor has "a checkered past," but is well suited for projects in the 600MW range. Russian reactors also have a negative perception in the market due to Chernobyl legacy.
- Track Record: They have been contracted by numerous governments on nuclear projects including Saudi Arabia, UK, and others. They also have a presence in region.

Credit Suisse

- Credit Suisse had a number of major concerns about financing the Project including the following:
  - The sovereign credit rating of Armenia is low.
  - Political risk is high due to a potential conflict with Azerbaijan.
  - The price of electricity is low even if the costs are passed to the end users.
  - The Project costs are very high.

Deutsche Bank

- Deutsche Bank expressed concern about the cost of the Project as well as nuclear permits and the structure of the decommissioning fund.

Mizuho Bank

- Mizuho noted that few banks have established internal country exposure ceiling limits for Armenia, which poses a challenge if the ECA backing the transaction provides less than 100% cover against commercial as well as political risks. US Exim, EDC (through its direct lending program) and ECGD are among the few ECAs that provide 100% commercial + political cover. Other ECAs including NEXI, EKN, CESCE, COFACE, ATRADIUS, EULER HERMES, and SACE all provide less than 100% commercial cover, which requires commercial banks to have a country exposure ceiling for Armenia.

BNP Paribas

- The Project is incompatible with their current priorities due to their belief that a long and complex implementation process may be necessary to bring the deal to fruition requiring the dedication of extensive resources over a significant period of time.

HSBC

- The Project is not of interest to HSBC.

Intesa Sanpaolo

- Nuclear power projects are not of interest to Intesa Sanpaolo.

Royal Bank of Scotland

- The Project does not fit the bank's current business profile.

Asian Development Bank (ADB)

Under their current energy policy, ADB is not allowed to finance nuclear power plants.

APPENDIX B TO CHAPTER 6:
ARMENIA NUCLEAR POWER PLANT: EC 6 COST OF FINANCING SUMMARY SHEET

General Assumptions

The table below illustrates the capital structure assumptions related to the Project based on our conversations with lenders and industry norms:

Capital Structure Assumptions		
Total Project Costs	3,558,490	in '000
Debt	75%	3:1 Capital Structure
Equity	25%	3:1 Capital Structure
Equity Assumptions		
Total Equity	889,623	25% of total project costs (in '000)
Cost of GoA Equity	10.0%	World Bank standard for developing countries
Cost of Private Equity	18.2%	Based on a levelized tariff analysis
Debt Assumptions		
Total Debt	2,668,868	75% of total project costs (in '000)
% of Debt from U.S. Ex-Im Bank	100%	

The total Project costs are based on the hard cost assumptions related to the Candu 6 reactor as well as the soft costs related to the Project. The soft costs include exposure and commitment fees to U.S. Ex-Im Bank, interest during construction, debt service reserve account, working capital and legal/consulting fees. The exposure fee makes up the largest component of the soft costs as it will be over $600 million based on the terms of the loan from Ex-Im Bank.

It is assumed that the Project's capital structure will be 3:1 debt to equity and that 100% of the debt will be sourced from U.S. Ex-Im Bank. The following table illustrates the expected terms of Ex-IM Bank debt:

U.S. Ex-Im Bank Terms		
Term	15	Years (not including grace period)
Grace (in years)	6	Interest only
Eximbank Exposure Fee (GoA)	29.37%	Risk Increment Level 0 b/c of sovereign borrower
Eximbank Exposure Fee (PPP)	29.37%	Risk Increment Level 0 b/c of sovereign guarantee
Eximbank Exposure Fee (Private)	29.37%	Risk Increment Level 0 b/c of sovereign guarantee
Commitment Fees	0.50%	per annum
Principal Payments	2	per year
Interest Rate	4.90%	swapped out LIBOR
Number of Payments	30	Over the life of loan
Interest Only Periods	12	Life of loan

The Exposure fee of 29.37% is based on the risk increment level 0, which is extended to sovereign borrowers such as the GoA. In the case of the PPP and the IPP, both structures will also qualify as sovereign borrowers due to the sovereign guarantees that must be provided by the GoA for each of these structures. Additional discussion on the terms and conditions of Ex-Im Bank debt is available in the Financing Strategy Document.

For each of the three scenarios, it is important to note that the Weighted Average Cost of Capital (WACC) could be lower to the extent that GoA can attract concessional funding or grants for the Project.

Ownership & Financing Structure A: Public Investment

The cost of financing for a wholly government owned plant is as follows:

Scenario A - Government Owned		
Total Loan Amount	2,668,868	75% of total project costs (in '000)
Cost of Equity	10.0%	World Bank standard for developing countries
Cost of Debt (Ex-Im)	9.9%	All-in cost of debt including interest & fees
WACC	10.0%	before tax benefit

The cost of equity for the GoA is assumed to be 10%, which is the World Bank's standard for developing countries. The cost of debt is a measure of the Internal Rate of Return (IRR) of all the cash flows to and from the lender for the life of the Project. The WACC is calculated as the IRR of all the future cash flows to and from the lender as well as the equity cash flows to and from the investor.

The cost of financing for this scenario is the lowest, since the GoA's cost of equity is lower than the cost of equity from private investors. As a result, this scenario results in the lowest tariff. The tariff is more than 30% lower than the IPP scenario. However, this scenario will also result in the highest fiscal burden for the GoA, as GoA will be responsible for 100% of the debt obligation.

Ownership & Financing Structure B: Public-Private Partnership (PPP)

The cost of financing for a public-private partnership (PPP) is as follows:

Scenario B - PPP		
Total Loan Amount	2,668,868	75% of total project costs (in '000)
PPP Portion of Equity (GoA)	50%	
PPP Portion of Equity (Private Investors)	50%	
Cost of Equity (GoA)	10.0%	World Bank standard for developing countries
Cost of Equity (Private Investors)	18.2%	Based on a levelized tariff analysis
Cost of Debt (Ex-Im)	9.9%	All-in cost of debt including interest & fees
WACC	12.3%	before tax benefit

The cost of debt remains unchanged since Ex-Im Bank treats the PPP as a sovereign borrower due to the sovereign guarantee provided by GoA. The cost of equity for GoA also remains at 10%. However, the total cost of equity must also consider the cost of equity for private investors. Based on the results of a levelized tariff analysis, the hurdle rate IRR (or minimum rate of return) for private investors is 18.2%. Since it is assumed that the partnership will be owned equally, with the GoA and private investors each owning 50%, the cost of equity will be higher for this scenario relative to scenario A. The WACC is calculated in the same manner as Scenario A, and is more than 2% higher than scenario A, as additional dividends must be paid out to private investors in order to meet their hurdle investment rate of 18.2%.

The resulting tariff is more than 15% lower than the IPP scenario, since the combined cost of equity is still below the cost of equity solely for private investors. This scenario also offers a lower fiscal burden than scenario A.

Ownership & Financing Structure C: Independent Power Producer (IPP)

The cost of financing for an independent power producer (IPP) is as follows:

Scenario C - IPP		
Total Loan Amount	2,668,868	75% of total project costs (in '000)
Cost of Equity (Private Investors)	18.2%	Based on a levelized tariff analysis
Cost of Debt (Ex-Im)	9.9%	All-in cost of debt including interest & fees
WACC	14.6%	before tax benefit

Once again, the cost of debt remains unchanged since Ex-Im Bank treats the IPP as a sovereign borrower due to the sovereign guarantee provided by GoA. The cost of equity for private investors or hurdle rate of investment remains the same at 18.2%. However, private investors now account for 100% of the equity investment in the Project. Therefore, additional equity cash outflows in the form of dividends are required in comparison to scenario B. As a result the WACC calculation is more than 2% higher than scenario B.

While the tariff is the highest in this scenario in order to meet the cost of equity for private investors, the GoA has the lowest financial exposure since the private sector has taken on the debt and equity obligations for the Project.

APPENDIX C TO CHAPTER 6: NATURAL GAS PRICE FORECAST

Armenia is primarily dependent on nuclear fuel and natural gas for base load power generation and on natural gas for peak load. Other fossil fuels are not readily available and transportation and environmental related costs makes them economically undesirable. Renewable sources such as wind and hydro are available but can not provide base load electric power on demand.

The price of natural gas is a major factor in determining generation cost and represents the single largest cost item included in retail electric rates. The significant uncertainty associated with the natural gas prices is due to unstable world oil prices and political factors.

The price of natural gas for Armenia has become one of the major, if not the most significant, source of uncertainty. The real challenge of forecasting the Natural gas price for Armenia was stipulated by two factors – international price dynamics and growth rates as well as Russia's "political" price formation mechanisms.

The very detailed analysis was performed within the scope fuel price forecast of LCGP 2005 and 2006. The results of that analysis identified the main driving factors, which are affecting fuel price at the international markets and within the region. It was noted that for the US and international markets Natural gas price is significantly impacted by the worldwide crude oil market price.

Although this conclusion may hold true for the U.S. market, it should not be universally taken for granted because a world natural gas market does not exist with respect to pipe supplied gas. This market is substantially more localized in its nature and formation of prices is to a much higher extent driven by availability and costs of pipe transportation routs. For previous LCGPs, in the approach to forecasting the natural gas price for Armenia, the most realistic internationally recognized forecasts of world crude oil prices were chosen. Furthermore, several important indictors were developed to relate these prices to natural gas prices and take into account peculiarities of the Armenia's regional natural gas market.

Although the latest price increases for fossil fuel, forecasts of the natural gas price for Europe is well in line with the projections of the EIA's world crude oil prices used as the basis for European projections.

The biggest factor affecting Natural Gas price in the region is related to the Russian former "political" price formation mechanisms. Russia was supplying Natural Gas to the former Soviet Republics by prices which were significantly lower as compared to the prices for European Union. With the average price above $US 300 per thousand cubic meters of Russian natural gas for the Western Europe in 2006, the gas prices for former Soviet Republics were the following:

- Belarus - $US 47;
- Southern Caucasus Republics - $US 54 - 110;
- Baltic States - $US 120 – 125
- Moldova - $US 160
- Ukraine - $US 230[5]

Armenia has been privy to discounted gas prices from Russia since the 90's. The price for the natural gas at the border for Armenia in 2006 was $US 54 per thousand cubic meters. In 2006 Armenia has been informed by its supplier that its gas prices will increase in 2006. The price at the border ($US 110) became effective January 1, 2007 and resulted in new prices for end-users, including thermal power plants.

The Table 1 below provides new/existing tariffs for natural gas customers established by the PSRC[6].

Table 1: Tariffs for Natural Gas Customers

		Unit	Tariffs for natural gas		Effective date
			VAT exclusive	VAT inclusive	
1	Tariff for ArmRusGas Ard CJSC sales to customers (2006-№298N)				January 1, 2007
1.1	for customers consuming monthly up to 10 thousand ncm	thousand AMD/ thousand n cu m	70,0	84,0	
1.2	for customers consuming monthly 10 thousand ncm and more	USD equivalent in AMD/ thousand n cu m	127,7	153,26	

While, Iran-Armenia gas pipeline could provide some level of competition for gas supply to Armenia, it was unlikely that the price of gas from Iran would be significantly lower than the price of gas from Russia. Moreover, attributing to the construction of the Iran-Armenia pipeline Russia took it under the control.

[5] Source http://news.bbc.co.uk/go/pr/fr/-/hi/russian/russia/newsid_4574000/4574984.stm

[6] Source http://www.psrc.am/en/?nid=218

Since the uncertainties related to Russia's "political gas price" were no longer an issue, only one scenario of fuel price increase, 2.37% per year, was used for LCGP 2006.

However, existing price for the Natural Gas supplied to Armenia is still lower than the market prices. The average Gazprom's gas delivery price for Europe have reached $410 per 1,000 cubic meters[7].

Gazprom describes the price hike as necessitated by the weakening U.S. dollar. However, according to Gazprom's assumptions the price increase would not affect the growing demand for natural gas on the European market.

Gazprom supplied 151 billion cubic meters of gas to the EU in 2007, and plans to deliver 157 billion cubic meters in 2008. The gas supplies to Western Europe were based on long-term contracts, most of which would only expire after 2030[8].

The gas monopoly is currently working on the Nord Stream pipeline project together with Germany's E.ON to pump 55 billion cu m of Russian natural gas under the Baltic Sea to Germany.

Another Gazprom project, the South Stream pipeline, involving Bulgaria and Serbia under agreements reached earlier this year, would pump 30 billion cubic meters of Central Asian gas to Europe. The project is receiving active support from Italy, Gazprom's second-largest gas market.

Other gas suppliers to EU such as Uzbekistan, Turkmenistan and Kazakhstan already announced that they would begin exporting their natural gas at European-level prices from 2009.

Gazprom is currently prioritizing Russian consumers. It has been cited that high economic growth and the influx of foreign capital into the real sector of the economy as driving forces behind Russia's energy demands. The rise of national industries, such as producers of cement, building materials, and fertilizers and gas refineries, is also pushing up gas demands. Gazprom plans to introduce market gas prices for Russian industrial consumers in 2011.

Mentioned above growing demand and market price, makes Russia's "political" price formation mechanism for Armenia hardly possible in a nearest future although the major assumptions driving the gas price, aside from political aspects, remains the same.

Based on above the following assumptions were made for the purpose of this study:

- The growth rate for natural gas price in next two years would be around 30% per year;
- Starting 2011 the natural gas price at the border of Armenia will reach the European price in five years;

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[7] Source http://en.rian.ru/business/20080610/109834595.html

[8] Source http://www.cdi.org/russia/johnson/2008-56-39.cfm

- The average growth rate for gas price delivered to EU and the growth rate for gas price delivered to the Armenian border after 2015 was assumed to be the same with the forecasted in LCGP 2006 (2.37% per year).

Figure 1 provides the forecast of natural gas prices for 2008 through 2030.

Figure 1: Natural Gas Price Forecast for Power Generation in Armenia