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Cost drivers for the assessment of nuclear power plant life extension

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FOREWORD

Over the last four decades, the worldwide growth of nuclear power generation has been significant. While in 1965 there were only 45 nuclear power plants (NPP) with a total electrical capacity of 4,833 MW(e) in operation in the world, in 2000 there were 438 NPPs with a total capacity of 351,327 MW(e). However, the rate of increase in new capacity appears to have slowed down considerably since the late 1980s, and the total installed nuclear capacity in the world has peaked towards the end of the twentieth century. This reduction in momentum results from a combination of factors, such as: saturation of the nuclear capacity in the generating capacity mix of several industrialized countries; deregulation of the electricity markets and privatisation of the power industry; competition from lower cost combined cycle gas turbines; the public concern about the safety of nuclear power plants and disposal of high level radioactive wastes.

To address the challenges of reducing the specific investment cost of nuclear power plants and to reduce exposure of regulatory risks to investors and nuclear operators, vendors are developing advanced nuclear designs competitive with conventional coal-fired power plants or combined cycle gas turbines in the future. In the interim, as operating nuclear power plants reach the end of the original design life, and the original investments have been fully recovered through depreciation or amortization of the original principle investment, the consequence of extending their operating life beyond the original planned life may result in nuclear power being competitive with the other options. However, this is a complex problem involving many issues, one of them being economics. The economic advantages of continuing operation of these plants should be demonstrated in the framework of cost-benefit analysis. One important factor for this analysis is the cost needed to continue operation beyond the planned life.

A previous technical publication of the IAEA, Review of Selected Cost Drivers for Decision on Continued Operation of Older Nuclear Reactors: Safety Upgrades, Lifetime Extension, Decommissioning, IAEA-TECDOC-1084, provided a review of published information on the three cost categories. An outcome of this report was the interest shown by Member States in this topic and the need for further studies on the costs of nuclear power plant life extension.

Based on the above, the IAEA initiated the task of preparing a technical report on “Cost Drivers for the Assessment of NPP Life Extension”. This publication develops a methodology to determine the cost inputs required to perform cost-benefit analysis for plant life extension schemes and presents cost and technical data on life extension/life management collected through a questionnaire sent to selected Member States. It can serve as a useful reference for the management staff within utilities, nuclear power plant operators, regulators, and other organizations involved in the assessment of NPP life extension.

The report was prepared in 1999–2001, by the Nuclear Power Engineering Section and Planning and Economic Study Section under the Department of Nuclear Energy, in the course of one advisory group and two consultants meetings. The IAEA wishes to express its gratitude to all experts who participated in the drafting and review of the report and to all contributors of cost and technical data on plant life extension. The IAEA officer responsible for this publication was M. Condu of the Division of Nuclear Power.

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1. INTRODUCTION

In the period of the nineteen-sixties to eighties, nuclear power had rapidly expanded in many countries of the world. The nuclear power plants built in this period, will reach the end of their planned life in the near future. Statistics drawn from IAEA's Power Reactor Information System (PRIS) indicate that, by the end of 2001, there were 175 nuclear power units (NPPs) with about 122 GWe of net electrical capacity, having 21 to 45 years of operation, (***Figure 1***). This represents about 34% of the total installed nuclear capacity in the world. Since these plants were initially designed for 30–40 years of operation, utilities operating such NPPs will now have to consider whether they will shutdown, decommission, and replace the plants reaching the end of their planned life, or refurbish the plants and extend their original design life. This decision is quite complex, involving a number of political, technical and economic issues. Finally, the utilities involved should manage their assets in a manner that is as close as practicable to the best possible economic optimum scenario.

Well before the end of the plant life, NPP operators must evaluate the technical and economic feasibility for PLEX options, seek and obtain regulatory approvals, and implement PLEX schemes that are justified. Often they also have to substantiate the planned life extension, including the economic viability to the relevant governmental bodies, as well as to assure the general public acceptance. Economic feasibility analysis requires cost data that are not readily available. A recent IAEA review of published information on costs of PLEX [1] revealed the scarcity of published information, while the estimated costs of NPP decommissioning are widely available. This is due in part to the reluctance by NPP operators to divulge the cost data that are considered commercial/confidential, as more plant operators are being privatised, and in part to the absence of a common framework and methodology to account for the various cost elements of NPP life extension or NPP life management (PLIM).

Within the context of this document, plant life is assumed to be the design life specified by the designer in the original design basis document or, if not available, the original economic design life specified by the operator and commencing at commercial operating date of the plant. PLEX is the operating period beyond the originally set plant life.

The report is structured as follows:

- Section 2 presents the current trends in the energy and electricity sector.
- Section 3 covers the recent IAEA and NEA activities in the area.
- Section 4 describes the purpose of the technical document.
- Section 5 discusses the decision process of PLEX, describes the overall framework in which the cost drivers of PLEX schemes are identified and categorized, and provides the reference PLEX cost driver matrix.
- Section 6 gives an overview of national and regulatory approaches on PLEX/PLIM, drawn from responses to the questionnaire provided from Member States, as well as from other available information. The basis of PLEX/PLIM cost estimates and scope of activities for each of the plants reported are also presented in this section.

- Section 7 presents the PLEX/PLIM cost ranges based on the responses to the questionnaire.

- Section 8 contains some general observations and conclusions.

At the end of the report references to the information sources used are given, as well as the list of abbreviations and the list of experts who contributed to the preparation of this document.

Four appendices provide complementary information: Appendix I presents Gentilly 2 case study; Appendix II gives a generic list of critical items with emphasis on PLIM for a PWR/PHWR NPP; Appendix III provides a PLEX cost driver matrix, to be used in the form of guidelines when evaluating PLEX costs; and Appendix IV presents the list of organizations providing responses to the questionnaire.

2. CURRENT TRENDS

One of the major trends in the global energy and electricity sector is the privatisation of electric utilities and deregulation of electricity markets. The increasingly competitive environment has significant impact on nuclear power. The old “Cost + Profit = Price” approach, where the profit is regulated independently of the cost, is replaced with the one based on “Price (market) – Costs = Profit”, where the price, cost and profit will require balancing to meet the market conditions. Competition from fossil fuels has increased. New and more efficient coal and gas technologies with comparatively low initial capital costs and substantially faster construction time schedules are being introduced. Joint studies by the International Energy Agency (IEA) and the Nuclear Energy Agency (NEA) have shown that new nuclear plants in OECD countries can only be competitive with other base load electricity generation alternatives under certain conditions. The competitiveness of new generation depends on factors that can vary considerably, such as: political, environmental and of course, the availability and cost of alternative fuels. Numerous studies have recently shown that for the commonly expected higher rates of return and short payback periods required today, it is difficult for new nuclear generation to compete with gas, combined cycle, or even with coal, in regions where coal is abundant and economical [2–3].

Although the nuclear industry has been working on improving the economics of nuclear electricity generation, such as evolutionary and innovative improvements of NPP designs, further developments in these areas will be needed to respond to changing market conditions. High capital cost and long lead time make it more difficult for the new NPPs to be competitive with alternative options of electricity generation in many countries. These disadvantages do not apply to existing plants, particularly when capital investments may have been depreciated over the operating years, or recovered through stranded cost and ownership transfer. With the exception perhaps of hydroelectric plants, well managed NPPs, with their increased safety and reliability, low fuel costs and minimized operation and maintenance costs, are often among the least expensive power plants operating today [3–6].

Therefore in this new framework, an area of immediate importance is managing PLEX, which for the short and medium term, may contribute to the potential preservation of nuclear contribution to the overall power generation. This contribution is becoming especially important due to positive role that nuclear power plays in mitigating air pollution and greenhouse gas emissions. In fact, should the climate change become a meaningful decision making factor, nuclear power is the only commercially available technology option that could replace fossil fuels in meeting base load electricity demand. Currently, the use of nuclear power avoids the discharge of some 8% of total carbon emissions from electricity production that would otherwise be through fossil fuels [3].

3. RECENT IAEA/NEA ACTIVITIES

IAEA has implemented a number of activities addressing various economic and technical issues on PLEX/PLIM:

i) The report Review of Selected Cost Drivers for Decisions on Continued Operation of Older Nuclear Reactors, IAEA-TECDOC-1084 was published in 1999. It provides a review of published information related to three cost categories: costs of safety upgrades necessary for continued operation of a nuclear unit, costs of lifetime extension measures, and decommissioning costs. The report views the costs globally, mainly as input for subsequent overall economic analysis.

ii) The activities related to the technical aspects of PLIM were implemented to facilitate the exchange of information and experience in monitoring the ageing mechanisms affecting the main NPP systems and components, provide guidance on lifetime limiting mechanisms and the impact of mitigating measures, as well as on the policies and strategies of PLIM programmes in Member States.

iii) Within the Safety Aspects of Nuclear Power Plant Ageing project, a programme of international co-operation for increased awareness and understanding of ageing degradation process has been established as well as for development of methods and guidelines to manage ageing for safe and reliable operation of NPPs.

NEA is also implementing a programme providing an opportunity for exchange of information on strategic and economic issues on PLIM/PLEX. As part of this programme the following topics were addressed:

i) International Common Ageing Terminology for Plant Life Management, was published in 1999 to improve the understanding of ageing phenomena, facilitating the reporting of relevant plant failure data, and promote uniform interpretations of standards and regulations that address ageing. This terminology is useful in the areas of PLIM/PLEX and aging management.

ii) A study by an Expert Group on Refurbishment Costs of Nuclear Power Plant was completed in 1999. The report includes cost data derived from experience and from plans to implement life extension or life management programmes in ten OECD countries (Belgium, Canada, Czech Republic, Finland, France, Hungary, Mexico, the Netherlands, Spain, and the United Kingdom). The Group decided not to publish the report and instead produced an internal document. The restriction was due to concerns expressed by participants about the confidentiality of some of the reported cost data and because the report does not include relevant data from non-participating OECD countries.

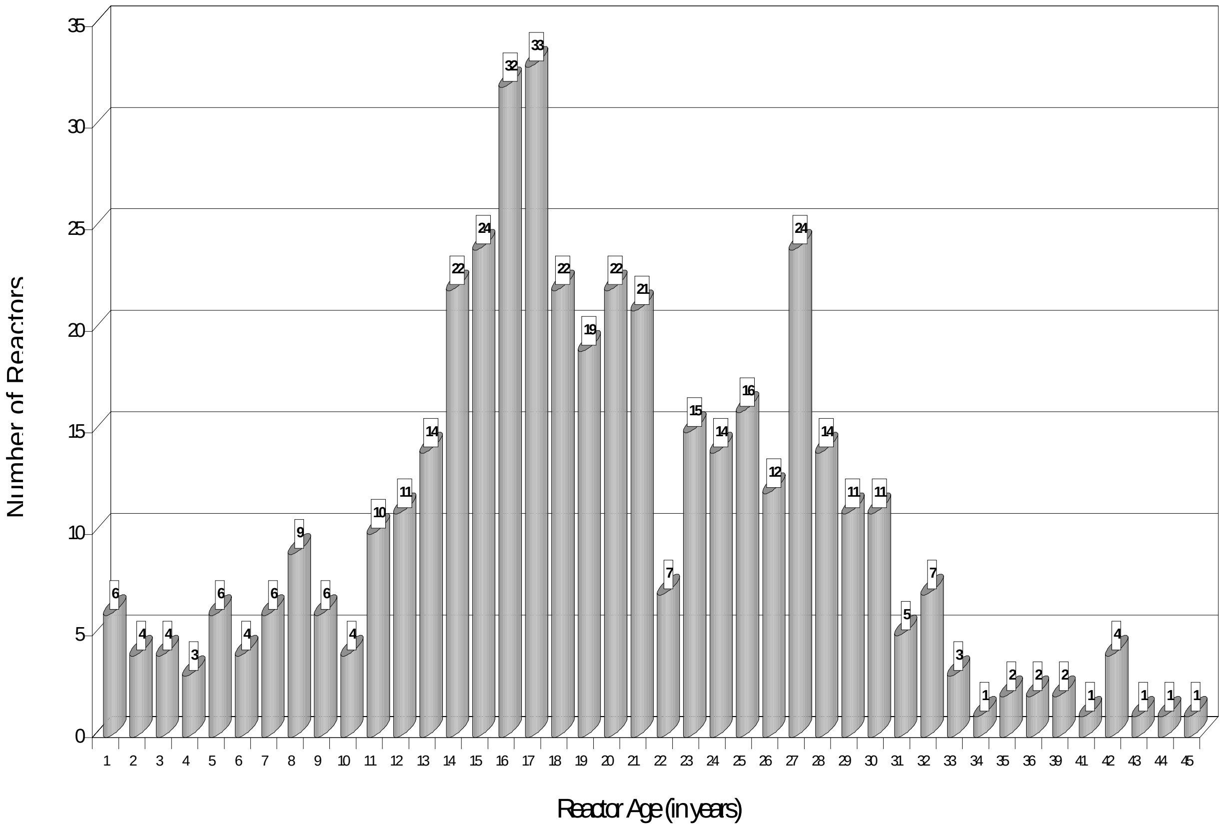


FIG. 1. Distribution of operating reactor units by age — as of 31 December 2001.

iii) Status Report on Nuclear Power Plant Life Management published in 2000, provides a summary of the current status of industry programmes and government policies for nuclear power plant life management in OECD Member Countries.

4. PURPOSE

The objective of this technical document is two-fold:

- To identify and describe the various cost elements and drivers in PLEX, and to provide methodology for estimating the costs of PLEX.

- To present PLEX cost data collected through a questionnaire distributed to selected IAEA Member States, and to assess the basis of the available cost estimates pertaining to different activities.

This information will assist NPP operators in developing cost estimates for PLEX. Economic benefits of PLEX can then be evaluated, providing part of the necessary input for optimisation of the power system (other inputs are: decommissioning costs, safety upgrades to ensure continued operation to the end of the original plant life, etc.). This is especially important in countries where deregulation and privatisation of the utilities requires a careful knowledge of benefits and risks associated with investments for NPPs.

5. METHODOLOGY

The purpose is to identify and describe the cost drivers & categories, and provide a working tool identified as the "cost driver matrix". This matrix is intended to assist the user in the PLEX cost estimation process. The methodology to estimate PLEX costs provided in this section includes also an overview of the decision making process.

The methodology focuses on the costs associated with PLEX in respect to labour and materials. This comprises costs over and above the normal plant running costs, and includes assessment work, design work, materials, procurement, and plant modification. In general, the data presented are overnight costs, with no allowance for discounting. Lost generation revenues during PLEX implementation work are not included in the reported costs.

To carry out a full economic appraisal of PLEX, additional cost data is required. This includes normal station operating costs, such as fuel, labour, materials, insurance and decommissioning. Other cost data required include alternative replacement generation costs. ***Figure 2*** illustrates a set of possible scenarios to meet the demand requirement.

The cost data, together with an estimate of generation income, can be combined to determine cash flows in future years for various scenarios. The cash flow data can then be used to obtain the net present value, with the assumption of an appropriate discount rate. However, such economic analysis is outside of the scope of this document.

5.1. Process to decide on life extension

The objective is to consider all cost drivers in a structured, logical order, as defined by three specific phases of this section. This process is illustrated in flowchart ***Figure 3***.

Decisions on life extension usually include consideration of regulation, environmental, economic, and governmental and public acceptance issues that have an impact on the cost drivers that are relevant to the evaluation of PLEX options. Although these factors are not explicitly addressed in the process described below, they are considered in Section 5.2.

Phase 1: Feasibility assessment and scoping of PLEX based on the technical assessment of Structures, Systems and Components (SSC), licensing issues and economic aspects.

Phase 2: Detailed evaluation and licensing application. It is only when the feasibility of PLEX is established that the operator proceeds to more detailed analyses, which in turn will lead to the preparation of licensing application & relevant documentation.

Phase 3: Implementation. This activity usually commences in parallel with the licensing process.

5.1.1. Phase I: Feasibility assessment and scoping

Well before (5–10 years) an NPP reaches the end of its design life, the operator should set up a task team to perform a preliminary study and analyse the technical and commercial aspects of the plant under PLEX consideration. From the engineering perspective, a screening of the SSCs should be carried out to determine the need for component and system replacements and/or upgrades required to meet the new expected service life. In parallel, licensing requirements for PLEX should be clarified or sought from the regulatory bodies; in the absence of such requirements, the operator should work cooperatively with the regulatory bodies to develop a conceptual framework to comply with the anticipated requirements.

During the scoping phase, all facts and data are collected to facilitate economic analyses to be performed, using assumptions that are consistent with the long term planning objectives of the enterprise. Cost estimates at this stage are based on best judgment. Depending on the available information, the economic analyses can range from project specific analysis, that is limited in scope, to a more rigorous system analysis that requires long term modelling of the entire power supply system, in order to evaluate competing scenarios.

Appendix I presents the Hydro Quebec (Canada) approach for PLEX economic assessment within this phase of the process for Gentilly 2 NPP.

In addition to the economic analyses, consideration has to be given to issues such as political, environmental, and public acceptance aspects that will determine the feasibility of PLEX.

Assuming that a PLEX option is feasible, a Phase II programme can proceed. At the end of Phase I, even though the preferred option is identified, a final decision to proceed has not been made. Hence, there is no major financial commitment by the operator at this stage. This phase may reveal mitigating measures that could be adopted in plant operation to effectively manage some of the plant aging aspects.

5.1.2. Phase II: Detailed evaluation and licensing application

If the PLEX option is demonstrated to be technically and economically viable in Phase I, Phase II may then proceed with emphasis on the critical SSCs, arising from the screening process completed in Phase I. Cost estimates further developed during Phase II should be based on firm quotations from component suppliers and contractors.

During this phase, as regulatory requirements become established, the operator can prepare licensing documentation for submission to the regulatory bodies. Also, public announcements and information meetings concerning the company’s intention with regard to the future of the plant may be held.

Towards the end of Phase II, formal applications to the regulatory bodies are made. This may be followed by a public review, where appropriate, before a license (or authorization) is granted. This process varies from country to country.

5.1.3. Phase III: Implementation

Phase III commences upon reaching an agreement in principle with the regulator on the basis of license extension (or authorization). Implementation of some PLEX activities can begin according to the agreement. At this time, financial commitments to the PLEX option will have been made and the cost of implementation is being firmed up. Some of the PLEX activities might be completed during the PLEX period, subject to agreement with the regulator.

For some utilities, a staged approach to the PLEX implementation is sometimes considered, in order to take advantage of seasonal variations in demand/market price and surplus capacity. Some of the PLEX related activities could be done on an opportunistic basis during the planned or unplanned outages. Some of these activities could be regarded as PLIM activities.

5.2. PLEX cost drivers

Major elements, which affect the cost of PLEX, are discussed herein as cost drivers. PLEX cost drivers typically include the incremental capital investments, and O&M costs required to extend the operational life beyond the design life. These may be incurred prior to, or during the life extension period. These cost drivers should be categorized as capital or non-capital components, based on the standard practices applicable to each country for the purpose of economic assessment.

5.2.1. Safety upgrades to meet regulatory requirements

These are upgrades necessary for the NPP to be operated beyond the original plant life up to a specific extended time period (e.g. 10-year extension). The need for such upgrades is based on current and anticipated regulatory requirements. The NPP operator should work with the regulator, in order to develop a framework for the requirements to reduce the associated risks. Safety upgrades are reactor-type specific, i.e. different for each reactor type, such as for PWR, BWR, WWER, PHWR, etc.

Usually, the NPP operator (with the assistance of the designer), and in consultation with the regulator, will identify a list of critical items[1] for any given plant. These are usually specific to the technical and regulatory requirements for the specific plant. A generic list of critical items for a PWR/PHWR NPP has been developed based on the experience of the contributors to this document and is presented in Appendix II. In addition to the identified critical items, other safety-related items must be evaluated to determine whether upgrades are necessary.

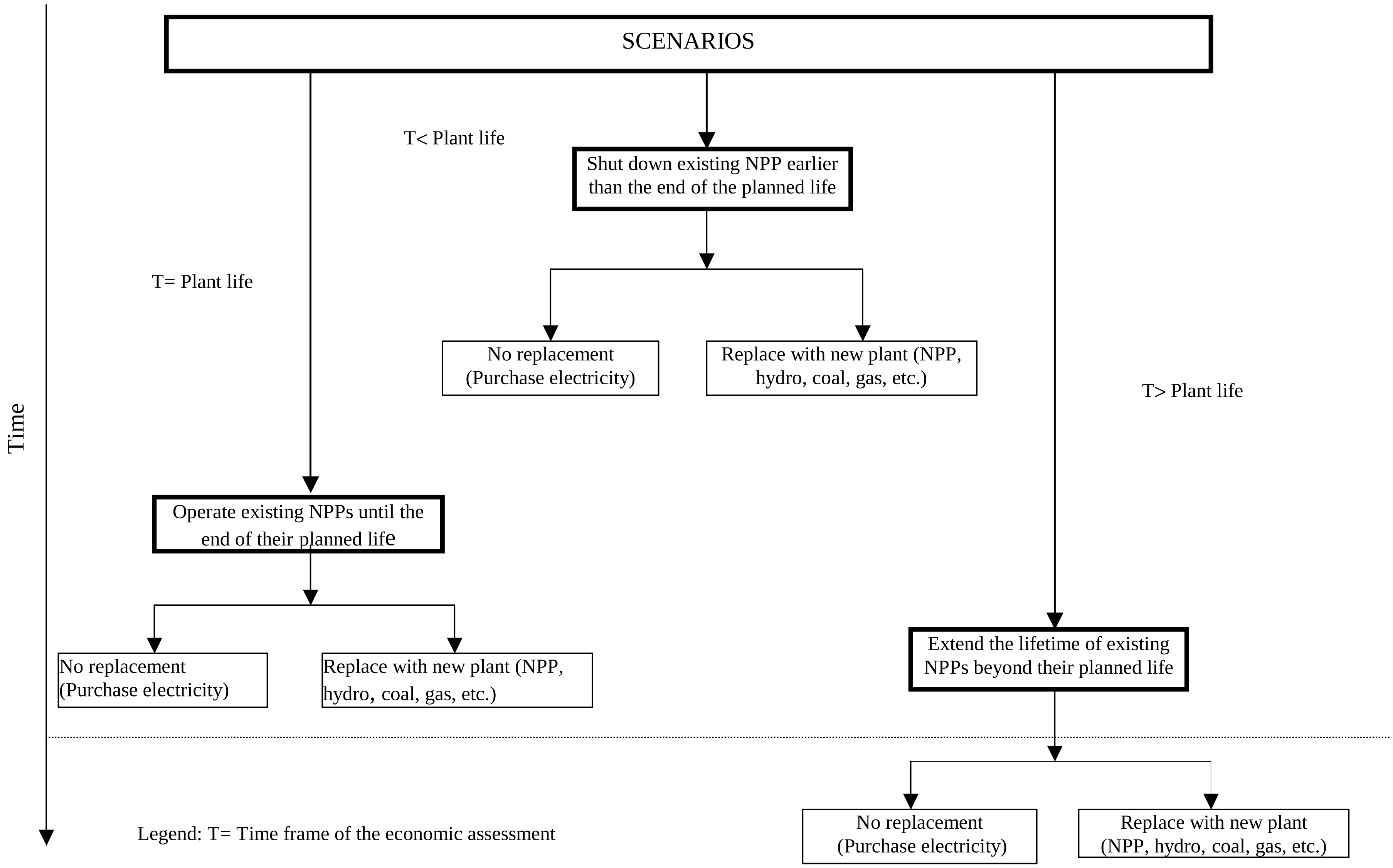
5.2.2. Other non-safety and conventional system upgrades

In addition to safety related systems and components, other non-safety and conventional system upgrades should be considered. They are aimed at improving the efficiency, increase plant output, increase reliability or optimise the operation and maintenance costs, each based on its own technical and economic merits.

[1] Critical items: Components considered impossible to replace, or which would need very costly repair or replacement. The definition extends to components for which the replacement cannot be included in the “normal” maintenance programs, and for which repair or replacement implies significant cost. The criteria used to establish the list include:

- Knowledge of the degradation phenomena;
- Impact of the different maintenance operations during the life time, on the availability of the plant;
- High cost of replacement or repair operations;
- Replacement recognised or postulated impossible; and
- Function of the equipment in the integrity of the confinement barriers as regards safety.

FIG. 2. *Sample PLEX scenarios.*



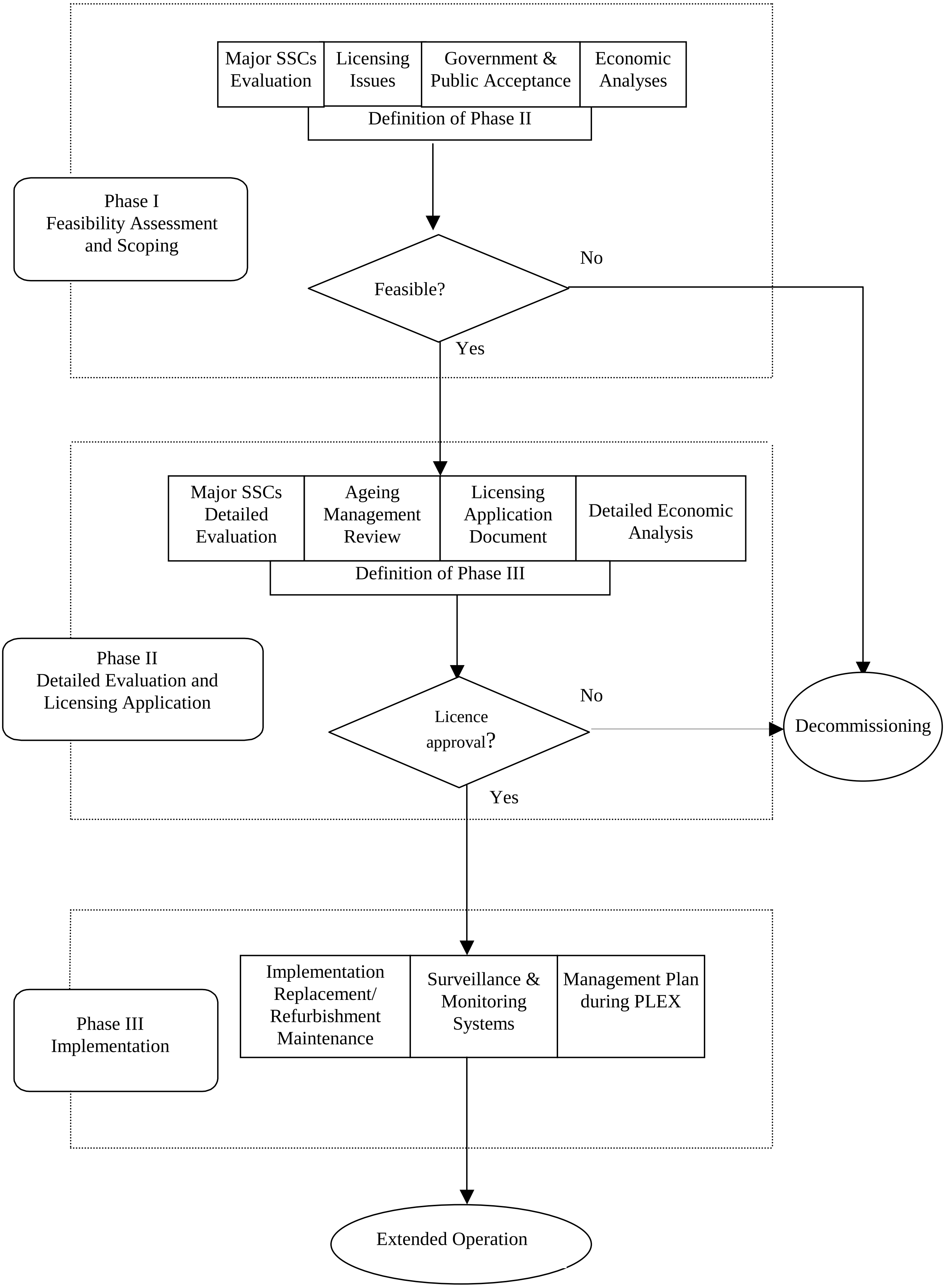


FIG. 3. Schematic example of PLEX decision process.

Such items could include, but not necessarily be limited to:

i) Nuclear and non-nuclear piping, power and control cables;

ii) Condenser;

iii) Power transformers and switchgear;

iv) Uprating of power output;

v) Environmental requirements;

vi) Fire protection upgrades;

vii) Civil structures;

viii) Turbine/generator;

ix) Communication equipment;

x) Cooling water piping and structures; and

xi) HVAC upgrades.

5.2.3. Management programs and processes

In addition to Safety and non-safety upgrades associated with improvements to the material condition of the plants, operators may be required to review and assess their internal management programs. This is usually achieved through self-assessment or by regulatory oversight, which, may lead to significant improvements of some, or all management programs and processes required for the continuous of safe and reliable operation of the plants. Examples of such programs and processes include but are not limited to:

i) Configuration management;

ii) Self-assessment;

iii) Corrective action;

iv) Design basis documentation;

v) Safety culture work environment;

vi) Work management;

vii) Computerized work management information System;

viii) Quality assurance and quality management; and

ix) Operator training and management oversight.

5.2.4. *Environmental impact assessment*

In some countries, an environmental assessment report of the impact of PLEX is required for regulatory and public review. The report addresses plant specific data in compliance with environmental regulations. These are usually distinct from the nuclear related regulations. Some countries integrate the environmental review process with the nuclear licensing process to avoid jurisdictional overlap.

5.2.5. *Maintaining expertise*

Countries that are not expanding their current nuclear program must ensure that their infrastructure maintains the capability to support the safe and reliable operation of the NPPs over their entire life. As the current complement of operating, maintenance and technical support staff ages and reaches retirement years, succession planning and training programmes are necessary to assure continued safe and reliable operation. Hence, the costs of implementing succession-planning programs, acquiring new skilled personnel and of in-house training programmes, should be included as a cost driver in PLEX. Costs of external training programmes that are funded at the national level may not be included.

5.2.6. *Public acceptance*

To ensure public acceptance to extend operation of NPPs beyond their originally intended life, public information, consultation and communication programmes may be developed and implemented. The costs of such programmes are the responsibility of the operators and should be reflected in the costs of PLEX options.

5.2.7. *Radioactive waste & spent fuel management*

Depending on the regulatory aspects of radioactive wastes and spent fuel management, as well as on the magnitude of the national nuclear power programme, the NPP operator may be required to evaluate many technical and economic issues related to the increased volume of radioactive wastes and the management of the incremental spent fuel arising from plant life extension. For example, if on-site storage of spent fuel is limited, the incremental wastes and spent fuel may be transported to other storage sites, such that incremental costs of transfer, receiving facilities, storage canisters or silos, transportation, storage fees, will be incurred. Alternatively, the originally planned storage facility may be expanded or compacted to accommodate the incremental volume, which in turn will trigger additional costs.

5.2.8. *Decommissioning*

For most developed countries, technical and costing aspects of decommissioning NPP at the end of plant life have been studied in detail, and a number of nuclear power reactors have been successfully decommissioned. In fact, for the majority of nuclear plant operators, financing provisions for the decommissioning of nuclear power plants are included in the price of electricity. Thus, at the end of the original plant life, the accumulated provisions for decommissioning should be sufficient to pay for plant shutdown, decommissioning, and return of the plant site to a "grey field", or "green field" state depending on the regulatory requirements in force.

In considering PLEX options, the financial implications must be carefully evaluated. At the end of the original plant life, a sum of money provided for by the users of electricity over the original plant life is ear marked for plant decommissioning. When the plant life is extended, the decommissioning process that was originally envisaged will be delayed for the duration of the extended period, so that interest may accrue on the unused decommissioning fund. Thus, evaluation of PLEX options must include the economic and financial aspects of delaying the decommissioning process by the PLEX period.

NOTE: This additional cost item should be added to the total cost of other alternate options to PLEX when performing the economic assessment.

5.2.9. Licensing process

The licensing process covers all costs incurred by the operator in the licensing process, leading to and including the issue and approval:

i) Costs of component life assessment studies and review;

ii) Technical and economic assessment of upgrading components and systems;

iii) Conceptualisation of PLEX options;

iv) Detailed technical and costing of the options;

v) Economic evaluation of all options;

vi) Preparation of licensing application documentation such as (including safety analyses, preliminary safety analysis reports, environmental impact statements, etc.);

vii) Preparation for regulatory and public review; and

viii) Responding to regulatory queries, etc. that leads to a decision by the regulators. Licensing fees and cost of the regulator (if applicable) should also be included.

5.2.10. Operating and maintenance (O&M) review

These costs include the total operating and maintenance costs (including fuel cost) incurred beyond the normal design life of the plant. To the extent that O&M costs are identified for each of the other cost driver categories, they should be included in this section. The PLEX option will have an influence on these costs, such as:

i) Review and up-grade of the plant management processes noted in Section 5.2.3 will trigger a review of O&M costs;

ii) If the PLEX is a highly probable option, some refurbishment and replacement tasks may be undertaken during the preceding planned outages as part of the PLIM program. These will have also an impact on O&M;

iii) Unforeseen regulatory requirements during PLEX authorisation may also impact on the O & M staffing plan. Any change must be estimated and factored in the economic assessment of the PLEX options; and

iv) PLEX costs should include the cost of the plant O & M and administration for the PLEX refurbishment outage.

5.2.11. Operating spares and consumables

An assessment of the need for operating spares and consumables must be performed, and the cost of procurement, supply, and storage of an inventory of operating spares should be estimated.

Operating experience of NPP indicates that it is prudent to maintain an optimal inventory of operating spares to ensure continued operation at high load factors with minimum interruption. While the supply of most common components is readily available from a number of suppliers, plans should be made to secure supply of specialised components with sole source supply, obsolescence of components, and items requiring long lead time.

5.2.12. Fuel cycle improvements

PLEX options may include changes and radical improvements to the fuel cycle, such as shortening of the re-fuelling downtime, improving fuel element configuration, using fuel bundle with higher enrichment levels, using mixed oxides fuel bundles, etc. The costs of those changes and improvements must be evaluated in connection with savings in the specific fuelling cost in the overall cost of electricity generation, and recognised as cost input to the economic evaluation of PLEX options.

5.2.13. Overall risk assessment

The following is a checklist of items for the assessment of risks. To the extent that is possible, they should be quantified in monetary terms for input to the economic analysis of PLEX options. For those risks that are difficult to quantify, an overall contingency allowance should be assigned to cover those risks. Effective on going risk management is a key factor in containing costs.

i) Rework errors;

ii) Faulty estimates;

iii) “Soft” pricing by vendors (budget vs. firm);

iv) Low field productivity;

v) Assumed cost (history data vs. recent quotes);

vi) Changes in regulatory requirements;

vii) Future change orders;

viii) Material/equipment specs (quality assurance/quality control changes);

ix) Unforeseen research & development requirements;

x) Late deliveries of materials/equipment;

xi) Labour relations problems;

xii) Project delays/deferrals;

xiii) Project management issues;

xiv) Inspection/rejects;

xv) Wage settlements impact;

xvi) Changing market conditions;

xvii) Interest rates impact;

xviii) Liquidated damages impact;

xix) Late start penalties; and

xx) Base quantities adjustment.

Contingency allowances for the cost drivers defined above should only be included in this section.

5.3. Cost driver matrix

In order to assist with categories and grouping of various impact items on the PLEX conditions, a working tool called the cost driver matrix was developed. It contains all cost drivers and associated cost categories, needed to be considered when performing the economic assessment of PLEX. It includes the feedback from the analysis of the responses to the questionnaire (see section 6). This working tool is intended to provide a systematic and comprehensive approach of the cost evaluation of PLEX. The cost driver matrix form is presented in Appendix III.

6. OVERVIEW OF NATIONAL & REGULATORY APPROACHES ON PLEX/PLIM

To validate the methodology developed and to facilitate sharing of technical and cost data information on PLEX among Member States, a questionnaire was prepared and sent out to utilities and other organizations in Member States having NPPs with more than 15 years of operation experience. Based on the answers to the questionnaire, this section presents a summary of the licensing process, national approach and the cost basis & scope of activities for the reported plants in respect to PLEX.

6.1. Questionnaire

The questionnaire, consists of three sections: data on the identity of the plant for which costs were reported and on national & regulatory approaches to PLEX; a detailed description of the PLEX cost drivers and categories, including guidance and instructions on how to formulate the answer; and the cost driver matrix. In addition it contains a confidentiality clause for commercially sensitive reported data. Since all the information (except the confidentiality clause) is presented in section 5 as part of the methodology developed, the questionnaire is not included in the technical document.

6.2. Overall review of responses

NPP operators from ten countries (Bulgaria, Canada, India, France, Japan, Korea, Netherlands, Russia, UK and USA) provided both, information on regulatory and national approach to life extension, and cost data. In addition, plant operators from other two countries (Armenia and South Africa) provided only information on regulatory and national approach to

PLEX, without cost data. The list with reporting organizations is included in Appendix IV. The total NPP operating experience in the reporting operator home countries (Table 1) represents about 77% of the total world operating experience at the end of 2001, of which 99% is from the countries providing the cost data.

Table 1. Reactor years experience from reporting operators' countries [7]

Country	Reactors Connected to the Grid (31.12.2001)				Total, Operating and Shut Down (31.12.2001)			
	No	Capacity MW(e) Net	Experience Years	Months	No	Capacity MW(e) Net	Experience Years	Months
Armenia	1	376	22		2	752	34	3
Bulgaria	6	3,538	119	2	6	3,538	119	2
Canada	14	10,018	215	2	25	15,548	447	2
France	59	63,073	1,008	11	70	67,024	1,228	2
India	14	2,503	195	5	14	2,503	195	5
Japan	54	44,289	971	5	56	44,461	1,016	4
Korea Rep	16	12,990	185	2	16	12,990	185	2
Netherlands	1	450	28	6	2	505	57	
Russia	30	20,793	616	1	34	21,574	701	4
South Africa	2	1,800	34	3	2	1,800	34	3
UK	33	12,498	967	6	45	14,306	1,270	2
USA	104	97,860	2,305	9	126	106,634	2,663	8
Total	334	270,188	6,669	4	398	291,635	7,952	1
Total world experience	438	353,298	8,626	9	533	385,895	10,363	1

The share of nuclear generation in reporting operators' countries is shown in Table 2.

Table 2. Total nuclear electricity generated and its share (end of 2001) per reporting operators' country [7]

Country	Nuclear generation [Net TWh]	Nuclear share [%]
Armenia	1.99	34.82
Bulgaria	18.24	41.55
Canada	72.35	12.85
France	401.30	77.07
India	17.32	3.72
Japan	321.94	34.26
Korea Rep.	112.13	39.32
Netherlands	3.75	4.16
Russian Fed. (RF)	125.36	15.40
South Africa	13.34*	6.65*
UK	82.34	22.44
USA	768.83	20.35

Note: Values with an asterisk are IAEA estimates.

PLEX/PLIM cost data were reported for five PWRs, one BWR, one Magnox, four WWERs and six PHWRs. These reactor types cover almost all commercially operated reactor types (except LWGR, ABWR and AGR) in Member States, and are currently providing about 328 GWe of a total of 353 GWe, or about 93% of all operating NPPs worldwide (Fig. 4 & Table 3).

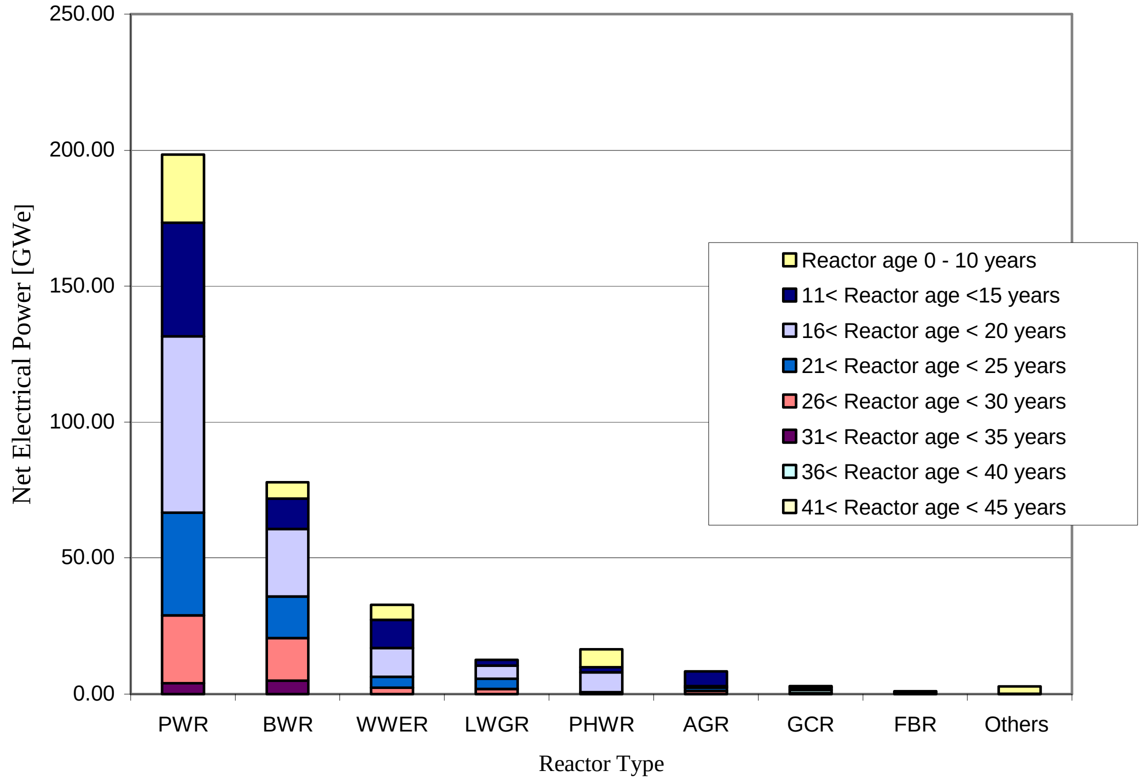


FIG. 4. Distribution of the net electrical power [GWe] by reactor type and age group as of the end of 2001 [7].

Table 3. Distribution of the net electrical power by reactor type and age group as of the end of 2001 [7]

[GWe]

	PWR	BWR	WWER	LWGR	PHWR	AGR	GCR	FBR	Others	Total
41< Reactor age < 45 years							0.40			0.40
36< Reactor age < 40 years							1.12			1.12
31< Reactor age < 35 years	3.99	4.93					0.92			9.85
26< Reactor age < 30 years	24.99	15.62	2.41	1.88	0.55	1.21	0.49	0.23		47.37
21< Reactor age < 25 years	37.73	15.38	3.91	3.71	0.19	1.21		0.56	0.148	62.83
16< Reactor age < 20 years	64.81	24.71	10.67	4.89	7.23	0.55		0.25		113.10
11< Reactor age <15 years	41.84	11.24	10.36	2.11	1.87	5.42				72.84
Reactor age 0 - 10 years	25.01	6.01	5.49	0.00	6.66	0.00			2.63	45.80
TOTAL	**198.36**	**77.88**	**32.83**	**12.59**	**16.50**	**8.38**	**2.93**	**1.04**	**2.78**	**353.298**

All of the reported data, with the exception of French ones, are base load generation capacities. The PWR data, submitted by EDF, represents a series of 18 NPPs (CP1 type). The responses vary considerably from one country to another, showing a variety of approaches for life extension/life management (Table 4). The data reported varies from comprehensive information – that covers full life extension approach, process and steps to assess its feasibility and costing, to responses containing limited type information on life extension, management, approach, and no cost information.

The national and regulatory approaches on PLEX/PLIM options revealed a variety of situations — some countries have an operating license for a limited term, while others do not have any special limits on their operating licenses, providing requirements for Periodic Safety Reviews (PSR). Accordingly, the approach to PLEX/PLIM is wide ranging — from a separate project approach, to a life management integrated approach. The extension periods considered, where applicable, span from 10 to 30 years beyond the original plant life. Some of the cost data provided refer to refurbishments within the original life of the plants (NPPs: Kozloduy — Bulgaria, CP1 Series — France, Rajasthan 2 — India, Borselle — Netherlands). All other cost data were reported for periods beyond the original life of the plants.

6.3. National and regulatory approaches for PLEX — basis of cost driver estimates

This section presents an overview of the licensing process, national approach and the cost basis for the reported plants in respect to PLEX. The content varies from country to country. Where available, additional information considered relevant for a comprehensive presentation of the country and regulatory approaches, was included.

6.3.1. Armenia

In 2001, the single nuclear unit in operation provided 34.82% of the total generated electricity. This nuclear unit was commissioned in 1980. In 1989 after the Spitak earthquake, it was shutdown and restarted 6 years later. It was designed and constructed for 30-year operating life.

The licensing process in force requires an operational license issued by the Armenian Nuclear Regulatory Authority for each restart of the plant following an annual outage. Activities are being carried out to estimate the remaining life of the plant and to assess the possibilities of operation beyond the design term. Currently, there is no anticipated decision for PLEX for this plant.

No cost data was provided.

6.3.2. Bulgaria

In 2001 nuclear plants produced 18.24 TWh, representing 41.55% of the total generated electricity. Bulgaria has 3538 MW(e) net electric power in six units of the Kozloduy NPP (KNPP).

The first two units with a total power of 816 MW(e) have 28 and 27 years of operation respectively, and are planned to be shut down in 2002 or 2003, before the end of their design life.

Table 4. Background information on responses to the questionnaire for reported plants

	Armenia	**Bulgaria**	**Canada**		**France**	**India**	**Japan**		**Rep. of Korea**	**Netherlands**	**Russian Fed.**	**South Africa**	**UK**	**US**
Reported NPP	Armenia 2	Kozloduy 5,6	Gentilly 2	Pickering 1–4	900 MW Series – 18 units (CP1)	Rajasthan 2	Not specified		Kori 1	Borselle	Kola 1 &2	Koeberg	Bradwell 1&2	Fort Calhoun
Reactor type	WWER	WWER	PHWR		PWR	PHWR	PWR	BWR	PWR	PWR	WWER	PWR	Magnox	PWR
Net power/reactor [MW(e)]	376	953	635	515	870–920	187	300–400	400–500	556	449		921	123	476
Commercial operation	1980	1988	1983	1971–1973	1981–1988	1981	Not specified		1978	1973	1973/1974	1984	1962	1974
Original life [years]	30	30	30		40	30	30		30	40	30	40	20	40
PLEX/PLIM for which the cost are reported [years]	not applicable	See par. 6.3.2	20	10	See par. 6.3.4	See par. 6.3.5	30		30	10(2003–2013)	10–15	not applicable(10 years life extension is considered)	10(from 40 to 50)	20
Operation type	Base load	Base load	Base load		Load following	Base load	Base load		Base load	Base load	Base load	Base load	Base load	Base load
Regulatory approach	Operating license for 1 year	Operating license for each fuel cycle	Operating license for 6 months to 3 years		Unlimited operating license +PSR at each 10 years	See par. 6.3.5	Unlimited operating license +PSR at each 10 years		Unlimited operating license +PSR at each 10 years	Unlimited operating license +PSR at each 10 years	1 year operating license	Unlimited operating license +PSR at each 10 years	Unlimited operating license +PSR at each 10 years	40 years operating license +max 20 years extension

A decision on continued operation of Units 3 and 4 will be taken in 2002. A major design limitation of Units 3 and 4 (advanced versions of WWER-4401 type V-230) is the small and limited primary containment (called confinement). Currently a comprehensive programme to upgrade these units is under way, intended to ensure effective performance of the confinement. The goal of the upgrading is to continue the plant operation until the end of their design life. If the technical solutions will be internationally accepted, and units 3&4 continue their operation, it will then be appropriate to initiate an evaluation of the PLEX option, for these units.

Units 5 and 6 are WWER-1000/V320. They were commissioned in 1988 and 1993, respectively. The design life of the units is 30 years. It is therefore too early to start evaluation of the PLEX option for these units. Currently, there is a vast Modernization Programme (MP) under way, for these units. The purpose of the MP is to eliminate some safety deficiencies of the design, which date to early 70s, and to increase the plants availability and plant’s operating conditions.

a) Regulatory approach

The basic law regulating the use of nuclear energy in the Republic of Bulgaria is the Act on the Use of Atomic Energy for Peaceful Purposes (AUAEPP), in force since 1985, supplemented and amended in 1995. The main document for application of the AUAEPP is the AUAEPP Enforcement Regulations (AUAEPPER) promulgated in 1986. At present, the Republic of Bulgaria is in a process of adjustment of the national legislation to that of the EC. The Committee on the Use of Atomic Energy for Peaceful Purposes (CUAEPP) is the organization responsible for the implementation of the National Program for the Adoption of “Acquis Communautaire” in the field of nuclear safety.

Licenses for atomic energy utilization are issued by the Inspectorate on the Safe Use of Atomic Energy (ISUAE) within CUAEPP, after receipt of the applicant's request in writing, specifying the activity related to the use of atomic energy, for which the license is requested. The request should be accompanied by the documentation, necessary for issuing a license, which is determined by this and other normative acts on the use of atomic energy (including Quality Assurance Programme for the corresponding activity). As provided in Regulation No 5, licenses have to be issued for every activity concerning safety, and commissioning of nuclear installations, for periods no longer than five years. The process is the same for each of the KNPP units. Practically, ISUAE issues the operation licenses for every unit for every fuel cycle.

There is no specified lifetime for the plant. In accordance with the original technical specifications, the design lifetime for the primary circuit equipment is 30 years. There is being implemented a project for evaluation of equipment and facilities residual lifetime. This project includes also development of an ageing management programme.

b) Basis of cost driver estimates

Drawing on the MP underway for Kozloduy NPP 5&6 (WWER-1000/V320), the following scope of cost drivers was identified (Table 5). The data provided represents estimates of material and labour and are based on vendors’ proposals.

Table 5. Scope of PLIM cost drivers reported for Kozloduy NPP 5&6 (Bulgaria) — WWER

Item	*Description*
1.	**Measures related to the RPV integrity – priority measures**
1.1.	- Heating water for high and medium pressure safety injection above 55^0 C
1.2.	- Develop a programme for studying reactor metal samples and determine the critical brittleness temperature
1.3.	- Study the irradiation resistance of the reactor vessel during the implementation of a new refuelling cycle
2.	**Measures for improvement of the reactor core control – priority measures**
2.1.	- Replace the "Hindukush" system with a more efficient one - core monitoring system
3.	**Installation of new systems to improve the safety and replacement of safety related equipment – priority measures**
3.1.	Replacement of Steam Generator (SG) safety valves
3.2.	Installation of hydrogen detection and recombination systems
3.3.	Improve the reliability of 6 kV breakers
3.4.	Improve reliability of diesel generators
3.5.	Installation of filtering ventilation for severe accidents
3.6.	Implement a critical parameters monitoring system for accident and post-accident situations
3.7.	Replace thermal insulation of equipment and piping located in the reactor building
4.	**Replacement of safety related electrical equipment**
4.1.	Improve the reliability of relay protection and automatics of the main distribution circuit
4.2.	Replace power breakers KAG-24
4.3.	Enhance reliability of generator excitation
4.4.	Ensure uninterrupted control of winding insulation of the turbine generator stator
4.5.	Ensure uninterruptible control of stator windings
4.6.	Ensure reliable control of operating temperatures of windings of main transformers and house transformers
5.	**Replacement of safety related I&C equipment and implementation of diagnostic systems**
5.1.	Replace the "Titan" information and computation system
5.2.	Replacement of universal control system (UKTS)
5.3.	Replace pressure drop sensors "Sapphire"
5.4.	Installation of system for detection of loose parts
5.5.	Installation of system for detection and localization of leakage from the reactor upper block
5.6.	Installation of system for monitoring of thermal cycles on coolant system piping
5.7.	Implement a safety parameters display system (SPDS)
6.	**Seismic re-qualification and reinforcement**
6.1.	Limit the effects of secondary circuit water or steam piping breaks in the containment

Table 5. (cont.)

Item	*Description*
6.2.	Check the seismic stability of the reactor department (mechanical analysis of the wall between of the reactor department and the turbine hall in the event of stream line and/or feed-water line break
6.3.	Enhance the seismic stability of carrying structures
6.4.	Implement the proposals to enhance the seismic stability of equipment
6.5.	Implement the proposals to enhance the seismic stability of piping
6.6.	Analyse the behaviour of safety systems' equipment in the event of an earthquake
6.7.	Study the seismic stability if buildings with the site seismic of 0.2 g
6.8.	Mechanical substantiation of supports of safety important piping in case of earthquake
7.	**Improvement of fire protection**
7.1.	Upgrade the fire resistance of fire doors
7.2.	Check fire propagation through air ducts
7.3.	Modify the gas fire extinguishing system
7.4.	Qualify fire alarm facilities for conformance with seismic stability requirements
8.	**Improvement of operation (The implementation of these measures will be decided after assessment of the economical effect)**
8.1.	Improve the containment test procedure and install appropriate measuring devices and computation facilities
8.2.	Study of implementation of additional protective functions for 6 kV and 0.4 kV motors
8.3.	Study on upgrading or replacement of 6 kV and 0.4 kV equipment
8.4.	Install additional Diesel Group (DG) per each unit for unit consumers
8.5.	Extend remaining life of SG blow-down system pipes
8.6.	Extend residual life of secondary circuit pipes operating in two-phase medium
8.7.	Replace condenser tube bundles with bundles manufactured from stainless steel
8.8.	Improve the reliability of circulation water filter of turbine condensers-Unit 6
8.9.	Develop a program for periodic tests of equipment in accordance with technical specifications
8.10.	Classify equipment according to rest life time and develop a system for rest life time evaluation
8.11.	Design visual and TV equipment inspection facilities
8.12.	Enhance facilities for primary circuit SG isolation during repair
8.13.	Develop methodology and techniques for replacement of small diameter piping sections provided with protection sleeves
8.14.	Develop training systems (training grounds) to train personnel on principles of dose load reduction
8.15.	Implement a system for continuous monitoring and maintenance of main primary circuit water chemistry indices
8.16.	Install systems and facilities for primary circuit sampling under accident conditions
8.17.	Design an automated information system for water treatment of units
8.18.	Modify water treatment system and reagent inventories
8.19.	Steam generator replacement project

One set of cost data was reported for Kozloduy Units 5 and 6. In order to allow a consistent presentation of data, we assumed that costs would be equally incurred in each of the two units, and filled in the tables accordingly for only one unit.

6.3.3. Canada

As of the end of 2001, Canada had 9998 MW(e) net of nuclear generated power electricity, in 14 NPPs, producing 12.85% of the total electricity. In addition, Canada had two laid-up NPPs — one at Pickering A, 4 × 515 MW(e), 24–26 years of operation and second at Bruce A, 4 x 848 MW(e), with 18–20 years of operation. These units initially performed well, but performance later declined due to inadequate operational and maintenance practices. The operator (Ontario Power Generation – OPG) developed a comprehensive nuclear recovery plan. Pickering A is undergoing a major retrofit, identified as Pickering A Return to Service (PARS), which brings the station back to the grid by 2002–2003. Bruce A has been long term leased to British Energy (BE), who is planning to rehabilitate up to three of these units.

a) Regulatory approach

In Canada, the Canadian Nuclear Safety Commission (CNSC), an agency of the Ministry of NRCan (Natural Resources Canada), is the federal regulator. A three-step procedure is used in the licensing of nuclear reactor projects in Canada. The first is site approval, followed by two formal licenses, the construction license, and the operating license, stating respectively the terms, under which construction or operation is authorised. The initial term of an operating licence issued by the CNSC is generally one year. The comprehensive staff evaluation of facility performance and positive recommendation are necessary before the Commission's approval to renew a licence is granted. There is no specific provision about the term or the renewal of the licence, either in the Atomic Energy Control Act, or in the Atomic Energy Control Regulations. They are at the discretion of the CNSC.

Historically, the CNSC operating licenses are renewed for terms between 6 months to three years, depending on the circumstances.

b) Basis of cost driver estimates

PLEX cost estimates were provided for Gentilly 2 (G2) and for Pickering A (Units 1–4) PHWR NPPs.

Gentilly 2 is a Candu type NPP, commissioned in 1983 as the first of the Candu 6 type unit. Further details on Gentilly 2 case study are provided in Appendix I.

Pickering A NPP, with a total capacity of 2060 MW(e), consists of four PHWR units of 515 MW(e) net each, and is operated by Ontario Power Generation (OPG). The units were commissioned between 1971 and 1973, and been laid up as part of a "nuclear recovery programme" announced in 1997. The recovery program consists of updating engineering designs and processes, developing new management and organisational procedures, implementing improved maintenance & work practices, and providing extensive staff training in all plants [8]. The technical program for re-licensing of Pickering-A concentrated on four basic areas: upgrading emergency shutdown systems; replacing pumps and other parts of the heavy water system to reduce leaks; improving air-handling systems to reduce atmospheric radiation emissions; and increasing the resistance of reactor control systems to seismic damage. OPG anticipates getting the reactors operating by 2002–2003 [9–10].

The cost estimates are based on the following:

i) All data represent estimates of labour and materials and not actual costs incurred. The exception is the cost of re-tubing for Pickering, which are actual costs (this operation was implemented in 1980s);

ii) Estimate for safety related upgrades are based on current and anticipated regulatory requirements;

iii) Steam Generators in CANDU plants do not usually require replacement for PLEX. Only rehabilitation (through water lancing and chemical cleaning) is assumed. Most rehabilitation tasks are undertaken as part of ongoing PLIM programs during planned outages and hence excluded in some cases form the PLEX costs;

iv) Fuel Channel Replacement (re-tubing) for CANDU plants is the major cost driver in CANDU refurbishment for life extension;

- For Gentilly 2: The cost includes replacement of all Pressure Tubes (PT) and Calandria Tubes (CT) in the core and a portion of all the inlet and outlet feeder pipes. The cost also includes construction of a protective concrete module for storage of radioactive PT/CT and Feeder piping removed during retubing;

- For Pickering A: It does not include the CT or feeder pipes replacement;

v) Project cost include costs related to environmental assessment, public consultation, detailed safety and regulation exploration, and life assessment studies for critical SSCs;

vi) Decommissioning costs include both dismantling and final spent fuel disposal. Based on a recent evaluation the dismantling costs are roughly the same with or without life extension. However if a decision is made between PLEX or building new fossil the dismantling costs are of less weight if they are to be spent later than sooner i.e. are more favourable to the PLEX option. This also applies to the final disposal of spent fuel. In that case, however, there will be about twice the amount of spent fuel bundles for disposal. So the disposal costs will be higher in today's money but not so when expressed in present value. At this stage these costs are not provided;

vii) Condenser retubing cost is included in the estimates;

viii) Cost for a selective cable replacement is included in the costs;

ix) Turbine up-rating is not assumed;

x) Other non safety related upgrades are assumed in the costs;

xi) Waste and Spent Fuel Management:

- For Gentilly 2: No additional spent fuel storage facilities are assumed since the current spent fuel bays store spent fuel underwater for 6 years at least then transferred to the MACSTOR dry spent fuel storage facility on site. This facility exists in most mature CANDU plants and is made of concrete modules where spent fuel is cooled by natural air convection. Each module can receive the spent fuel bundles produced in about 2,5 years of normal production. The construction of those modules and the transfer costs are considered part of the operating costs. The storage bay was designed to store 10 years of operation about 80% capacity factor plus a full core of fuel bundle inventory;

- For Pickering A: Costs for storage and disposal of additional fuel bundles are included.

xii) The cost of the plant O & M and administration:

- For Gentilly 2: This cost for the 18 months refurbishment outage is included in the PLEX cost for comparison with other non nuclear replacement options;

- For Pickering A: This cost was not provided, while it has been considered in the economic assessment on the life extension option;

xiii) Some allowance was made for unknown refurbishment/rehabilitation work that will be done as part of ongoing PLIM programs to preserve the option of PLEX at a later date or knowing that such option is adopted (only for Gentilly 2); and

xiv) For Pickering only: One set of cost data was reported for all 4 units of NPP Pickering A. As most of the respondents reported the costs for only one unit, and in order to allow a consistent presentation of data, we assumed that costs would be equally incurred to each of the four units and filled in the tables accordingly.

The scope of PLEX cost drivers reported for Gentilly 2 and Pickering are presented in Tables 6 & 7.

6.3.4. France

In 2001, France had 59 NPPs, having a total net installed power capacity of 63,073 MW(e), and provided 77.07% of all the electric power produced in the country.

a) Regulatory approach

In France the regulator is the Direction de la Surete des Installations Nucleaires (DSIN), and its technical support the Institut de Protection et de Surete Nucléaire (IPSN). It is under the authority of both the Ministries of Industry and Environment. It does not give a license for a specified period of time. The design life of the units is 40 years. The Safety Authorities give an authorization to restart each unit after reloading at the end of each cycle (roughly every 12 to 16 months, depending on the series and the fuel cycle retained).

An agreement has been reached between EDF and the Safety Authorities, in order to minimize the need for long outages, to implement modifications during each 10 years outages during which a complete check-up of the unit is performed, according to the regulation.

Table 6. Scope of PLEX cost drivers reported for Gentilly 2(Canada) — PHWR

Item	***Description***
1	**Safety upgrades to meet regulatory requirements**
1.1	*Critical equipment & systems*
1.1.1	Reactor complete retubing
1.1.2	Station control computers replacement
1.1.3	Isolation door between spent fuel reception bay and storage bay
1.1.4	Regulation provision
1.2	*Documentation*
1.2.1	Safety re-evaluation
2	**Other non safety and conventional system upgrades (improvements & up rate)**
2.1	Selective cable replacement
2.2	Condenser replacement (condenser retubing only)
3	**Licensing process**
3.1	License renewal after refurbishment (expenses that could be required to comply with multiple requirements from the regulator)
4	**Public acceptance**
5	**Environmental impact assessment**
6	**Overall risk assessment**
6.1	Minor but numerous corrections or upgrading during the 1,5 years of refurbishment
6.2	Updating design documentation (during the 3 years preceding the refurbishment)
6.3	Maintenance review (during the 5 years project phase)
6.4	Provision for unknown modifications (during the 5 years project phase)
7	**Other remaining costs**
7.1	Pre-project
7.2	Project administration (over the 5 years project phase)
Item	***Description***
7.3	New fuel for startup after refurbishment (this is the half core load that is considered to be charged to the refurbishment project. The other half is charged to the regular O&M costs)
7.4	O & M and administration (This is the normal O & M and administration applicable to the 18 months of the refurbishment outage. On a preliminary basis, it has considered it as being applied to the project cost, in the comparisons with the non-nuclear replacement options).

Table 7. Scope of PLEX cost drivers reported for Pickering A(Canada) — PHWR

Item	***Description***
1	**Safety upgrades to meet regulatory requirements**
1.1	*Critical equipment & systems*
1.1.1	Steam Generator remediation
1.1.2	HPECI upgrade
1.1.3	Shutdown system enhancement
1.1.4	ECIS recovery strainers
1.1.5	Biological shield cooling upgrade
1.1.6	Environmental qualification
1.1.7	Seismic improvements
1.1.8	Reduction of severe core damage frequency
1.1.9	Retube in 1980s
1.2	*Documentation*
1.2.1	Safety analysis update
1.2.2	System code classification registration
1.2.3	Systematic review of safety
2	**Other non safety and conventional system upgrades (improvements & up rate)**
2.1	Selective cable replacement (EQ), see 1.1.6
2.2	Condenser replacement
2.3	Turbine/generators major maintenance
2.4	Overhaul of fuelling machine systems
2.5	Electrical overhauls
2.6	Valve refurbishment (AOV/MOV)
2.7	Pump maintenance
2.8	Main power output (transformer)
2.9	Feed heating system upgrades
2.10	Replacement of DCCs
2.11	Service water systems
2.12	Standby generator (EPS) upgrade
2.13	Relief valve refurbishment
2.14	Replace class II MG sets with inverters
2.15	Replace moderator heat exchangers
2.16	Fire protection upgrade program
2.17	Screen house upgrade
2.18	Upgrade vapour recovery system
2.19	Rehabilitation of reactor building air conditioning units
3	**Environmental impact**
3.1	Environmental impact assessment
3.2	Replacement of stack monitors
3.3	Replace poly-chlorinated bi-phenyl (PCB) filed components
3.4	Asbestos abatement
4	**Maintaining skills**
4.1	Training
5	**Waste & spent fuel management**
5.1	Increased spent fuel storage
5.2	Increased spent fuel disposal
6	**Licensing process**
6.1	Safety and licensing

Table 7. (cont.)

Item	*Description*
7	**O&M optimisation**
7.1	Conduct of operations
7.2	Conduct of maintenance
7.3	Preventive maintenance optimisation
7.4	Configuration management restoration
7.5	Engineering programs
8	**Operating spares assessment**
8.1	Spare parts

These modifications are defined taking into account the results of a PSR, which is performed ***for the whole series***, before the considered ten years outage of the first unit of the series. According to the results of the PSR and of the context of the modification batch proposed (the same on all the units of the series) the series is allowed to be operated for 10 more years (except if a specific problem on one unit make it a particular case).

Presently, the oldest 900 MW units — 24 years old (CP0 series) and 21 years (CP1 series), have been implicitly authorized for a 30-year operating life, even if a justification file has been submitted for operation up to 40 years.

The Safety Authorities have publicly expressed that they will not consider a life extension request before the 3rd ten years outage, and not for more than 10 years at a time. Such a request has not been decided yet, even if some additional necessary data are prepared, and some mitigating measures taken in order to allow such a demonstration.

b) Basis of cost driver estimates

To date no decision to launch a comprehensive life extension research program has been taken by EDF. Therefore the information and data provided hereafter are only those derived from the existing life management program (aimed at proving the possibility to operate the units up to the end of their design life of 40 years). The following framework applies:

- As EDF policy is to maintain the series effect, which is the basis of the French NPPs, the same modifications are implemented on all units in a single batch of modifications, during each ten-year outage.

- The replacement of critical components is implemented at the same time with the batch of modifications, but only on the unit(s) requiring it.

The scope of PLEX cost drivers reported is presented in Table 8. The cost data provided for CP1 PWR Series are based on the following conditions:

i) The costs provided, except for 2.3 — Generator rewinding — are costs of operations already performed on at least one unit of the series, in the framework of PLIM.

ii) Small modifications (items 1.2 and 2.4 in the table below):

iii) Average one unit value of the cost of the batch of modifications implemented during the 2nd ten-year outage is the total cost for the series divided by the number of units in the series. These costs include generic engineering, procurement, construction and tests.

iv) Costs associated with one component: Cost incurred on one individual unit, non-necessarily the same than for the same component at another unit.

v) Engineering costs: Except when site specific, the cost is the generic cost of the design of the modification, divided by the number of units to which it applies.

vi) The total cost is a weighted average total, taking into consideration the number of units on which the replacements or modifications are already performed and forecasted, out of the 18 CP1 units. It does not include either the modifications, which were performed on all units during the first ten years or those, which will be included during the 3rd ten years outage, on all units.

Further considerations for PLEX:

i) No PLEX cost will be considered for reactor vessel, as the duration of extension is limited to the acceptable vessel life.

ii) No spent fuel management costs for PLEX are foreseen due to reprocessing.

iii) No operating spare parts assessment seems necessary for PLEX.

iv) In case of PLEX decided, it is obvious that ***all*** the operations listed here below, even if priced and already performed on one unit, ***will not be performed —*** on all units for which life extension will be decided, especially if such a replacement has already be performed during the design life. Even if it is not the case, regarding the operational history of each unit, most of the replacements or refurbishment listed will not be necessary. Correspondingly, all ***improvements,*** which could appear necessary or useful on the occasion of PLEX, will be implemented on all the concerned units.

v) Due to the series effect, the extra costs coming from the limitation of irradiation of workers, and also from retraining of workers who did not work in controlled areas for a long time, are limited, as they work on one unit or an other one nearly all year long, at least during a ten years period, and can work outside the irradiation zones on preparation works when their irradiation limit is reached (even during potential PLEX works, heavy maintenance activities by modification batches will go on the newer series).

vi) There are SSCs requiring no special activities (other than normal maintenance) in the PLIM context, therefore the need and/or costs for PLEX are not identified yet. For example: core internal structures, electric cables for nuclear systems, primary pumps, bimetallic connections, charging pumps, emergency electric supply, feedwater pumps, civil works (nuclear island), valves, turbine up rate.

6.3.5. India

As of December 2001, India had 2503 MW(e) installed nuclear power base, consisting of 14 operating units (2 BWRs and 12 PHWRs), which provided 3.72% of all the electric power produced in the country.

Table 8. Scope of PLIM cost drivers reported for one generic CP 1 NPP (France) — PWR

Item	***Description***
1	**Safety upgrades to meet regulatory requirements**
1.1	Critical equipment & systems
1.1.1	Steam generator
1.1.2	Reactor vessel head replacement (including CRDM removal/re-welding)
1.1.3	Large diameter primary circuit pipes (cast elbows)
1.1.4	Guide thimble pins replacement (including thimble tube replacement)
1.1.5	Control rods monitoring
1.1.6	Anchoring (piping supports)
1.1.7	Lifting equipment improvement
1.1.8	Fuel handling improvements
1.1.10	Fire protection improvement (average)
1.1.11	Improvement of periodic tests
1.2	PLIM « Small » modifications. Not including the items here above
2	**Other non safety and conventional system upgrades (improvements & up rate)**
2.1	Condenser replacement (re bundling)
2.2	Turbine LP cylinder replacement
2.3	Generator stator rewinding
2.4	PLIM « Small » modifications. Not including the items here above

a) Regulatory approach

The nuclear power plants are authorized to operate by the Atomic Energy Regulatory Board based on a Safety Review Process. Normally authorization to operate is granted for five years. However, performance of the station is reviewed on a regular basis for adherence to the station technical specification.

b) Basis of cost driver estimates

The case reported by India builds on actual experience gained in the rehabilitation of Rajasthan Atomic Power Station (RAPS) Unit 2, a 200 MW(e) PHWR type unit located on the bank of Rana Pratap Sagar. It went critical on 8th October 1980, synchronized on 1st November 1980 and started commercial operation from 1st April 1981. It operated very successfully and by August 1994 it completed 8.2 full power years of operation. Based on the in service inspection, carried out to assess the health of coolant tubes made of Zircalloy-2, a decision was taken to replace all the coolant tubes of the reactor and the station was shut down in August, 1994 for En-masse Coolant Channel Replacement (EMCCR). This gave the best opportunity for carrying out large scale activities related with safety improvement, ageing and obsolescence management, and plant performance improvement. The scope of these large scale activities is presented in Table 9. After renovation RAPS-2 was made critical on 27th May 98, and was synchronized to grid after physics and safety experiments on 4th June 98.

Table 9. Scope of upgrade activities for RAPS Unit 2 (India) — PHWR

Item	*Description*
1	**EMCCR:** All 306 coolant channels were removed. New coolant channels made of Zirconium 2.5% Nb were installed, which are expected to last much longer. New tubes have 4 tight fit garter springs of modified design in place of 2 used earlier.
2	**PHT SYSTEM**
2.1	Shutdown cooler, bleed cooler and pre-cooler replacement
2.2	Wall thinning in feeder elbows: the six feeder elbows, which were found to have less than 10 years of residual life, have been repaired by qualified weld deposit procedure
2.3	Retrofitted emergency core cooling system: high pressure injection system retrofitted and redundancy provided in long term re-circulation
3	**MODERATOR SYSTEM**
3.1	Deletion of fast pump-up system
3.2	Moderator heat exchanger replacement
4	**DOUSING SYSTEM MODIFICATION:** fixed flow instead of modulating flow provided. Flow reduced to 30% of the original maximum flow
5	**CONDENSER RETUBING**
6	**ELECTRICAL SYSTEM**
6.1	Segregation of power and control supplies and cables
6.2	Additional DG Set for RAPS-2 and RAPS-1&2, class-III interconnection
6.3	250 VDC batteries replaced
6.4	Fire barriers and fire retardant paint provided.
7	**CONTROL AND INSTRUMENTATION**
7.1	Supplementary control room introduced
7.2	Control & instrumentation for retrofitted ECCS
7.3	Control & Instrumentation for modified dousing system: electronics based provided in place of pneumatic one
7.4	Up gradation of fire detection and alarm system
7.5	Up gradation of channel temperature monitoring system
7.6	Up gradation of reactor regulating system to microprocessor based
7.7	Startup Instrumentation to take care restart after EMCCR work
7.8	Plant information system - computer based provided
7.9	Old analog controllers replaced with digital programmable controllers
7.10	Replacement of electronic transmitters, indicators, electro-pneumatic converter & resistance
7.11	Transmitters residual life estimation for instrument hardware and cables was carried out
7.12	Segregation of safety related control cables to prevent common mode failure
8	**FUEL HANDLING SYSTEM**
8.1	Logic card up gradation
8.2	Remote viewing system renovated
8.3	Spent fuel inspection bay panel renovated
9	**INSTRUMENT AIR**
9.1	Dedicated instrument air supply to essential loads: provided to reduce instrument air in-leakages during building isolation in case of LOCA
9.2	Operation and fail safe position of safety related valves during common cause failure was reviewed

Six PHWR units have pressure tubes of older design, which have shorter life compared to the plant life.

Based on the experience gained in the rehabilitation of RASP Unit 2, India has provided cost data for the drivers shown in ***Table 10***. As mentioned above, the cost drivers and data provided for India are related to PLIM.

Table 10. Cost drivers reported for RASP Unit 2 (India) — PHWR

Item	*Description*
1	EMCCR
2	Reactor systems including heat exchangers
3	Electrical Systems
4	Control & Instrumentation
5	ECCS
6	Simulator up gradation
7	Building & Structure
8	Mechanical systems
9	Indirect Cost
9.1	Establishment & General
9.2	Power
9.3	Maintenance
9.4	Others (fuel, D_2O, IDC, etc)

6.3.6. Japan

In 2001, 54 NPPs with a total net installed power capacity of 44,289 MW(e), provided 34.26% of all the electric power produced in Japan.

a) Regulatory approach

Under Japan’s present legislation, a nuclear power plant licence is granted for an indefinite period. There is no specific regulatory point of view, therefore no specific regulatory process in place for plant life extension. A periodical inspection system is defined, and a nuclear power plant is shutdown yearly to undergo annual inspections before approval to operate for another year. MITI endorses the safety of a plant as long as it meets the safety standards at the time. The electrical utilities also implement inspections on their own initiative during this plant shutdown period. Nuclear power plants can continue to operate as long as the operator can prove annually that the plant can operate safely for one more year. In addition, periodical safety review shall be conducted at each plant at approximately 10-year intervals.

Based on MITI’s concept approach to aging, the following applies:

i) As a standard, SSCs shall totally be assessed after 30 years of operation;

ii) Accordingly, the content of the maintenance activities for an approximately 10-year period shall be specified and practiced as scheduled; and

iii) 10 years thereafter, overall reassessment shall be conducted.

In 1996, the Ministry of International Trade and Industries (MITI), the regulatory authority in Japan, has launched a program to provide a conceptual framework by which the integrity of aging nuclear power plants are examined and addressed, using three plants that have been in operation since 1970/71 (Mihama 1, Tsuruga 1 and Fukushima Daiichi 1) as pilot projects [11]. This programme assumes that the plants will operate for 60 years.

The technical evaluation of the major components/structures of these plants and the basic concept for dealing with the aged plants are considered to be phase one. The major SSCs to be evaluated are identified by considering the following criteria: safety related SSCs, not easy to repair and replace, and long term ageing issues. There have been identified 8 components and one structure for PWR, and 6 components and one structure for BWR. It is considered that plant integrity can be maintained for a period exceeding 60 years from a technical standpoint through continued proper inspection and maintenance activities.

In the second phase, the utilities conduct the detailed technical assessment of integrity on a wider range of components of the above mentioned three leading power plants, taking into account not only a safety point of view, but also the perspective of avoiding an unscheduled shutdown in order to develop measures against ageing degradation. Based on this assessment, the utilities review the completeness of integral components, which are important for the safe and continuous operation of these power plants. Also, the methods and periods of inspection and maintenance can be evaluated from this assessment for future implementation.

Upon completion of phase two, the identified important factors will be reflected in the long term maintenance program of the utilities and in the periodical inspections conducted by the government. The comprehensive long term maintenance of the aged plants is scheduled to be established when they will reach 30 years of operation.

Kansai Electric, the operator of Mihama - 1 NPP, which had 30 years of operation in November 2000, announced that it intends to continue to operate this unit for a minimum 10-years period, during which it would implement a long term maintenance programme and carry periodic inspections. There would then be a formal safety review at the end of 10-year period, followed by an overall assessment of whether or not to continue operations. The long term maintenance program was developed based on the evaluation of the long term integrity and the validity of the current maintenance program, covering about 2000 SSCs with about 30000 items [12].

b) Basis of cost driver estimates

On the basis of plant life assessment conducted after 30-year operation, the following were clarified:

- In order to continue the plant operation just a limited number of SSCs are required upgrading.

- Sixty-years operation will be possible by conducting repairs or replacements when necessary with reviewing the scope of maintenance and continuing degradation management.

The scope of PLEX cost drivers reported for BWR and PWR are presented in Table 11 & 12. The cost estimates for Japan both reactor types are based on the following:

i) There is no specific regulatory body requirement concerning SSCs improvement for PLEX. Cost drivers #1 and #2 include only SSCs for which replacements are expected in the future and their costs are estimated to exceed 0.879 MUSD (100 MYen). The smaller items are included in “Other costs” driver.

ii) Except SSCs listed under item 1 in tables below, there are no SSCs requiring refurbishment costs estimated to exceed 0.879 MUSD.

ii) All cost less than 0.879 MUSD related to the PLEX cost drivers are listed under “Other remaining costs in tables below.

iii) The cost of the documentation (such as technical documentation, manuals, instructions, etc.) is included in the supply contract with manufacturers.

iv) Currently the radioactive wastes and spent fuel are stored within the plant sites in the existing pools. These costs are included in O&M costs. Spent fuel storage outside the plant sites is being investigating and cost data are not available.

v) Decommissioning cost of a plant is estimated as about 260 MUSD and depends on the generating capacity of the plant. The required amount is accumulated every year during operation. Continuing plant operation will not change these costs.

vi) Although there are no regulations pertaining to PLEX in Japan, the utilities have to assess the plant life after 30-year operation and conduct periodic safety review once every 10 years. The costs to implement these activities were provided.

vii) The regulator does not require environmental impact assessment for plant life extension.

viii) Consideration is being paid to the use of fuel with more enriched Uranium, but this is not specifically related to PLEX and no data was provided.

ix) The “Operation spares assessment” and “Operation and maintenance optimisation” cost drivers are considered to be part of regular O&M costs and no data was provided. No data was provided for “Maintenance skills”, “Public acceptance” and “Overall risk assessment cost divers”.

6.3.7. Republic of Korea

The first nuclear power plant (Kori 1) has been connected to the grid in 1978. At the end of 2001, the total net installed power in NPPs was 12,990 MW(e), supplying 39.32% of the total electricity produced in the country.

Table 11. Scope of PLEX cost drivers reported for a BWR NPP (Japan)

Item	***Description***	***Number of Components***
1	**Safety upgrades to meet regulatory requirements**	
1.1	Feedwater heater	10
1.2	Control rod drive mechanism	97
1.3	Process computer	
1.4	Main turbine (final stage rotor blade disk)	
1.5	Main generator rotor	
1.6	Reactor pressure vessel welded materials volume inspection	
1.7	High pressure injection turbine	1
1.8	Moisture separator	4
1.9	Component cooling water heat exchanger	3
1.10	Main steam safety relief valve/main steam safety valve	7
2	**Licensing process**	
2.1	Life extension assessment	
3	**Other remaining costs**	
3.1	Reactor core isolation cooling turbine	1
3.2	Residual heat removal heat exchanger	2
3.3	Main steam isolation valve actuator	8 sets
3.4	Reactor recirculation pump motor	2
3.5	Reactor recirculation pump (main shaft, impeller)	2

Table 12. Scope of PLEX cost drivers reported for a PWR NPP (Japan)

Item	***Description***	***Number of Components***
1	**Safety upgrades to meet regulatory requirements**	
1.1	Steam generator	2
1.2	Turbine	1(HP & LP)
1.3	Core internal	
1.4	Reactor vessel head	
1.5	Pressuriser	
1.6	Emergency DG	2
1.7	Reactor coolant pump	2 internals
1.8	Condenser tube	1 set
1.9	Process computer	
1.10	Circulating water pump	2
1.11	Moisture separator and reheater	2

Table 12. (cont.)

Item	***Description***	***Number of Components***
1.12	High pressure feedwater heater	2
1.13	Component cooling water heat exchanger	2
1.14	Residual heat exchanger	2
1.15	Low pressure feedwater heater	6
1.16	Deaerator	
1.17	Feedwater pump	3
1.18	Regenerative heat exchanger	
1.19	Condensate pump	3
1.20	Control rod drive mechanism	1 set
2	**Licensing process**	
2.1	Life extension assessment	
3	**Other remaining costs**	
3.1	Airlock	
3.2	Residual heat removal pump	2 rotors
3.3	Gland steam condenser	

a) Regulatory approach

In accordance with the KEPCO strategy [13], a comprehensive plan for the Plant Life Management (PLIM) has been conducted since 1993. The primary goal of KEPCO’s PLIM is to operate nuclear plants safely and economically for the original design life of the plants. If this first goal is achieved, then the operation of nuclear power plants beyond the original design life will be pursued as the second goal. The second goal of the PLIM program is to operate plants for their optimum lifetime. A plant-specific feasibility study was developed to evaluate each plant's optimum lifetime, which was the plant target life for the PLIM efforts. If the optimum lifetime for a plant is longer than its design life, then additional activities to extend the lifetime will be incorporate into the long term or predictive maintenance programs for the plant. In parallel with the PLIM program, Periodic Safety Review (PSR) required by the government to enhance the safety of NPP is being developed.

The master plan for PLIM, including the continued operation of Kori Unit 1 and other nuclear power plants in Korea beyond their original design life, is composed of three phases as shown in Table 13.

Table 13. PLIM Programme (Republic of Korea)

Phases	***Period***	***Contents***
Phase I	1993–1996	*Feasibility Study* - Feasibility evaluation method and techniques - Kori Unit 1 LMNPP feasibility - Phase II planning
Phase II	1997–2001	*Detail Evaluation and Engineering* - Kori Unit 1 detail inspection and residual life evaluation - Documentation for license renewal - Planning for life extension
Phase III	2001–2008	*Refurbish, Replacement. and Maintenance* - Implementation - Advanced technology development

Kori Unit 1 is the leading plant for above PLIM (and PSR) and the categorization generically stems from the level of details and refinement that are to be accomplished during each phase of the project. The feasibility of life extension for Kori Unit 1, in terms of technical, regulatory and economic aspects, was established in phase I by performing the field data survey, screening and prioritisation of the SSCs, aging evaluations of the prioritised 13 major SSCs and economic evaluation of the Kori 1 PLIM. In the phase II program, detailed lifetime evaluations and aging management review for the major components and other critical components has been performed. In parallel, PSR is under preparation to review the safety issues of the other SSCs of Kori Unit 1. The PLIM implementation plan for phase III will then be developed later based on the results obtained in the preceding activities.

All nuclear reactors in Korea are licensed to be operated without a time limit and PSR is scheduled to be conducted for the every 10 years.

The original design life of the Kori 1, leading plant, is considered as 30 years based on the FSAR description. However the design of most major components, including reactor pressure vessel, was based on 40 years.

Although regulatory requirements are essential for the continued operation, there are no such rules yet in Korea. Considering that the implementation cost for plant refurbishment or backfitting are strongly affected by regulatory requirements, continued operation may or may not be feasible depending upon the requirements of the regulations. As a result, the regulatory body try to make rule effectively.

Continued operation requirements shall include the licensing period, the standard for evaluation and the implementation planning considering the all-foreign experiences.

b) Basis of cost driver estimates

All cost data are estimated values for a Korean NPP assuming the 2 Loop PWR (600MW(e)) – Kori 1. The scope of PLEX cost drivers reported is presented in Table 14. The cost data stems from the database of Korea Power Engineering Company with the following engineering judgments and assumptions:

i) Supply cost is based on the procurement database of system or equipment considering the experience of Korean Standard NPP (KSNP);

ii) R&D cost is assumed as 5% of supply cost except RPV and SG. The R&D cost of RPV and SG are estimated as up to 20% of the supply cost considering the experiences and assumed plant specific situation;

iii) According to the industry experiences for Korean Standard NPP, 30% of supply cost is assumed as the engineering cost and construction cost reflects the difficulty of the replacement or large repair for operating NPPs by using some correction factors; and

iv) Plant specific conditions related to the replacement/refurbishment experience of the components are considered adequately.

Table 14. Scope of PLEX cost drivers reported for Kori 1 NPP (Republic of Korea) — PWR

Item	*Description*	*Remarks*
1	**Safety Upgrades to meet regulatory requirement**	
1. 1	Reactor Pressure Vessel including Internal Construction Cost	
1. 2	Steam Generator (2EA)	Replaced ('98)
1. 3	Pressuriser	
1. 4	Reactor Cooling Pump except Motor (2EA)	
1. 5	Reactor Cooling System (RCS) Piping including Surge Line	
1. 6	Emergency Diesel Generator (2EA)	
1. 7	Post Actions for Three Miles Island (TMI) Accident	Assumed Cost
1. 7. 1	Operator Aid Computation System	Added ('98)
1. 7. 2	Post Accident Sampling System	Added ('98)
1. 7. 3	Wide Range Detection System for Accident in Containment	Added ('98)
1. 7. 4	Acoustic Detection System for Leakage of RCS	Added ('98)
2	**Other significant industry related items**	
2.1	Reactor Vessel Internal	
2.2	Service Water System	
2.3	Circulating System	
2.4	Reactor Cooling Pump motor (2EA)	
2.5	Low Pressure (LP) Turbine Rotors (2EA)	
2.6	High Pressure (HP) Turbine	
2.7	Instrument Air System except piping	
2.8	Charging pump (3EA)	
2.9	Component Cooling Water piping, heat exchangers, tanks, valves	
2.10	Main Feed Water (FW) Pump (3EA)	
2.11	Condensate Pump (3EA)	
2.12	Circulating Water Pump (4EA)	
2.13	Auxiliary Boiler	
2.14	Auxiliary FW Pump (3EA)	
2.15	Pipe (Main Steam, FW, etc)	
2.16	Heat exchangers (LP, Medium Pressure (MP), HP)	
2.17	Main Steam Safety Valve (10EA)	
2.18	Process Control/Protection System	
2.19	Nuclear Instrumentation System (excore)	
2.20	Control Cable	
2.21	Manifold, Sensing Tube	
2.22	Fire Extinguishing	
2.23	Condenser Tube	
3	**Waste & Spent fuel management**	
4	**Other non safety and conventional system upgrades (ducts, condenser input/output piping, generator/exciter**	
4.1	Ducts	
4.2	Condenser input/output piping	
4.4	Generator/Exciter	
5	**Licensing process**	
6	**Public acceptance**	
7	**Environmental impact assessment**	
8	**Overall risk assessment**	
9	**Other remaining costs**	

6.3.8. Netherlands

The only NPP in operation in the Netherlands has a net power of 449 MW(e). It is owned and operated by N V Elektriciteits Productiemaatschappij Zuid (EPZ). In 2001 it generated 3.7 TWh, representing 4.16 % of the total electricity produced in the country.

a) Regulatory approach

The plant has been put in commercial operation in 1973 and has a 40 years technical design life. Actual licensing regulations require a PSR every ten years to continue the license.

The plant original investment being paid off in 1993, EPZ decided to invest and upgrade the plant to 1993/94 state of the art technologies in order to run it for another 20 years. A new safety concept was developed were a new design basis based on deterministic regulations combined with the findings of PSA was defined. The new predominant external events considered were: earthquake (0.1g); gas cloud explosion; aircraft crash; flooding; and loss of ultimate heat sink. As regards internal events, the piping of the primary loop was analysed to satisfy the criteria of a leak-before break concept. The main steam and feedwater piping, which cannot be demonstrated to have leak-before-break were replaced. To meet the new design basis back fitting measures were implemented in seventeen areas including: decay heat removal; ECCS; emergency power system; reactor protection system and backup control room fire protection; and containment. Among the key modifications: a new emergency power system; additional redundant decay heat removal with a well water system; new primary safety/relief valves; etc. Following the backfitting the total core damage frequency improved from 5.6×10^{-5}/year to 4.5×10^{-6}/year [14–15].

Due to an agreement with Dutch Utility Board, the total KWh price had to be comparable with the KWh price for a new gas combined cycle plant (about 8 US Cent/KWh). As the normal operation and fuel costs were about 6 US Cent/KWh, and for 10 years granted operation, the budget the ceiling for investment was determined to be 475 MNLG. The project could be implemented for about 467 MNLG (250 MUSD-97) [14–15].

The next PSR is due in 2003.

b) Basis of cost driver estimates

The cost estimates provided for NPP Borselle NPP are based on the following:

i) At the moment, the preparations are undergoing for the next PSR (2003) to cover the period 2003 until 2013. On this PSR PLEX will be a main issue of consideration. Large costs for PLEX are not expected due to the thorough PSR and follow-up in 1993 and the implementation in the years 1994 until the end of 1998. The costs provided herein are those estimated to be necessary to get the Regulatory Body authorisation for continued operation from 2003 to 2013.

ii) The NPP Borselle is on bases of the 1993 PSR upgrade in the years 1994 until the end of 1997. This includes software and hardware modifications (for further details please refer to 4.3.6). During the PSR of 1993 PLIM was (and still is) a main issue of consideration.

iii) Also there were implemented upgrading including HV-aged cable replacement (1997); condenser tube replacement (1984); change secondary chemical treatment (1986); major modifications to heat exchangers, preheaters, separators and reheaters (1973 – 1984).

iv) Operating spares assessment is an undergoing action and shows some potential problems in the future. A number of potential problems are eliminated by buying large quantities of special chips between a numbers of utilities together with the manufacturer. From other utilities, which upgraded their electrical components, obsolete components where bought in order to delay the decision of upgrading. These actions were taken over the last five years.

The scope of PLEX cost drivers reported is presented in Table 15.

Table 15. Scope of PLIM cost drivers reported for NPP Borselle (Netherlands) — PWR

Item	***Description***
1	**Safety upgrades to meet regulatory requirements**
1.2	Documentation
1.2.1	Safety re-evaluation
2	**Waste & spent fuel management**
2.1	Increased spent fuel storage
3	**Public acceptance**
4	**Environmental impact assessment**

6.3.9. Russian Federation

Presently, there are 30 nuclear power generating units in the Russian Federation that operate in 10 separate nuclear generating power stations, providing 15.4% of the total electricity production.

a) Regulatory approach

During the design development, and commissioning of the former soviet made NPPs, a 30-year period was considered as plant lifetime. However the original design life for these plants has not been officially stated in the NPP regulatory documentation. This 30 years period is used for amortization purposes. In addition, 30-year lifetime is given by the designer/manufacturer as a guaranteed operational lifetime for certain types of equipment.

Of the 30 power units connected to the grid in the Russian Federation, the oldest are Novovoronezh 3 and 4 and Kola 1 and 2, commissioned into commercial operation between 1971 and 1975. “ROSENERGOATOM”, the operator for these NPPs, has decided to extend the lifetime of these power units for a further 10 years.

Currently, regulatory body (GAN of Russia) has already adopted the federal regulatory document “The main requirements to NPP power unit life extension” (NP-017-2000).

Detailed consideration of this document by ROSENERGOATOM concluded that the regulatory requirements for PLEX (beyond 30 years design life) could be met.

b) Basis of cost driver estimates

The basis of PLEX consists of the application of international practices combined with national operating experience and regulatory requirements, utilising the detail technical specifications for key equipment. Initially the process involves equipment lifetime investigation and the performance of the In-Depth Safety Assessment (INDSA).

Based on the results of the lifetime extension investigations, the decisions on extending the equipment operational lifetime or the need to replace equipment are made by the operating management of the NPPs. Such investigations have started at Novovoronezh NPP units 3 and 4 and Kola NPP units 1 and 2. The equipment to be replaced has been identified. The second area of activities for the decision making process on lifetime extension for these units is the in-depth safety assessment. The results of this assessment allow identification of “gaps” between the safety requirements (current or anticipated) and real safety conditions of the plants. Safety up-grades “to fill in the gap” will need to be implemented in order to obtain the NPPs extended operating license from the regulatory body.

Thus, “ROSENERGOATOM” life extension related activities at Novovoronezh NPP 3 and 4 and Kola NPP 1 and 2 are currently focused on these two areas. “ROSENERGOATOM” started financing these activities in 1999. All effort devoted to this issue for the period of 1999–2000 may be split into the following major categories:

- Development of operating procedures, specifications, research work, performance of tests and investigations (INDSA, investigation of residual lifetime etc.);
- Capital investment (purchase of new equipment, upgrade of safety systems, strengthening of the physical protection at the power units etc.); and
- Miscellaneous (insurance of civil liabilities due to nuclear hazards, licensing, additional contracting additional nuclear fuel, additional expenditures related to the nuclear waste reprocessing and spent nuclear fuel handling etc.).

However, the aforementioned approach to the NPP lifetime extension issue is primarily applicable to the first generation of power units, which were commissioned in accordance with earlier safety requirements.

The policy of “lifetime management”, constant control of equipment conditions and continuous safety enhancements can reasonably be applied to the second generation of NPP units that are closer to meeting current national safety requirements. The strategy of constant, continuous investment into these power units should result in a smooth transition to PLEX.

The PLEX cost estimates provided for Kola NPP 1 & 2 are based on the following:

1. All data represent estimates of labour and materials and are based on PLEX cost estimates approved by ROSENERGOATOM. All of this data is considered as a financial plan for PLEX option;

2. Safety related upgrade are based on current regulatory requirements;

3. During PLEX the replacement of steam generator for Kola 1&2 is not required. PLEX includes only upgrade of steam generator blow-down system;

4. The reactor core internals will not be replaced or upgraded and the design of the fuel will be maintained;

5. Project costs include cost related to detailed safety and regulatory exploration and life assessment studies for critical SSCs;

6. Decommissioning costs include both dismantling and final spent fuel disposal;

7. Cost for specific electrical system and cable replacement are included;

8. Turbine up-rating is not considered;

9. Waste and spent fuel management include capital cost for the construction of an additional storage facility (dry) and annual cost for transportation, reprocessing and storage of spent fuel generated during 10–15 years of PLEX;

10. The O&M costs are not included; and

11. One set of cost data was reported for Kola Units 1 and 2. In order to allow a consistent presentation of data, we assumed that costs would be equally incurred to each of the two units and filled in the tables accordingly for only one unit.

    The scope of PLEX cost drivers reported is presented in Table 16

6.3.10. South Africa

The only NPP in South Africa – Koeberg, PWR, 2 x 921MW(e) net– is owned and operated by ESKOM. It was commissioned in 1984 (Unit 1) and 1985 (Unit 2). The NSSS supplier is FRAMATOME.

The license to operate Koeberg has been issued by the National Nuclear Regulator (NNR). No term is specified for the license as it is predominantly based on risk to operators and the general public with a large emphasis placed on Probabilistic Risk Assessment (PRA) techniques. The NNR interfaces with Koeberg through ESKOM Corporate with NNR inspectors on site. It is further required that every 10 years a Periodic Safety Review (PSR) be performed to evaluate the plant against an international reference plant. This is currently the French 900MW safety referential. The first PSR was carried out in 1998. The plant life, as defined in chap. 1 is 40 years and the depreciation is charged over 25 years.

The life extension considered by ESKOM is 10 years. The viable economic lifetime of 50 years is a formal management directive to challenge responsible operation of the plant. However, ESKOM does not view nor intends to manage the operation of Koeberg past the current design life of 40 years as a separate project. To implement and give credibility to this, the utility has been developing over the past two years, Life of Plant Plans (LOPP) for major Plant, Structures, Systems, and Components (PSSC's).

Table 16. Scope of PLEX cost drivers reported for
NPP Kola 1&2 (Russian Federation) — WWER

Item	***Description***
1	**Safety upgrades to meet regulatory requirements**
1.1	*Systems*
1.1.1	System of reliable power supply for 2nd group consumers
1.1.2	Emergency core cooling system and spray system
1.1.3	Emergency auxiliary steam generator make-up system
1.1.4	Important consumers service water system
1.1.5	Increasing of containment leak tightness
1.1.6	Replacement of turbine hall roof insulation
1.1.7	Fire protection of turbine hall structures
1.1.8	Accidents localization system
1.2	*Documentation*
1.2.1	In-depth safety assessment (report)
2 2.1	**Other non safety and conventional system upgrades (improvements & up-rate)** Equipment residual resource justification and replacement of equipment which achieved end of life.
3	**Waste & spent fuel management**
3.1	Increased spent fuel storage
3.1	Costs of spent nuclear fuel supplementary disposal for 10 years of PLEX
4	**Decommissioning (supplementary charges for 10 years)**
5	**Licensing**
5.1	Licensing process
5.2	Examination of documents to receive licenses
6	**Operating spares assessment during extended operation period (10 years)**

Life Cycle Plan is being developed to document major interventions and associated basis to ensure the most economical strategy to manage the PSSC over a 50-year life span. This project is not completed and is being done in close collaboration with EDF. Each LOPP includes the expenditure profile to refurbish or upgrade the necessary PSSC over the considered economical viable lifetime of the station. This viability is continuously assessed and successful PSR reports will validate ongoing operation.

6.3.11. United Kingdom

In the UK, there are 15 nuclear power stations in operation with a capacity of about 13 GWe, supplying 22.44% of the total electricity requirement. These comprise seven operational Magnox units, seven AGR units and one PWR unit. Of the 13 GWe supplied by nuclear, Magnox stations contribute about 25%, AGR plants about 65% and the PWR plant 10 %. Since 1989 four nuclear power stations have ceased electricity production and are in the process of decommissioning. The operational Magnox stations have planned closure dates of between 40 and 50 years as shown in Table 17.

Table 17. Planned closure dates for Magnox plants

Station	*Planned closure date*	*Age*
Calder Hall	2006/8	50
Chapelcross	2008/10	50
Bradwell	2002	40
Dungeness A	2006	40
Sizewell A	2006	40
Oldbury	2013	45
Wylfa	2016/21	45/50

UK NPPs had lifetimes defined at the time of design for economy purposes. These lifetimes range between 20 and 40 years.

a) Regulatory approach

Regulatory arrangements are well established for the review of safety in the context of longer term operation. Each NPP has a site licence, which is issued by the nuclear regulator The conditions of the site licence are standardized for all nuclear plants but arrangements specific to each plant had to be submitted by the operator for the agreement of the regulator. One condition concerns statutory shutdowns during which plant inspections are carried out. Each reactor is shutdown every 2 or 3 years for such inspections and the agreement of the regulator is required before the reactor can return to service. A further license condition is the need for the licence holder to complete PSRs every 10 years of operation. These reviews concern the nuclear safety case for the operation of the plant over a further 10 years. The effects of ageing and the need to update plant safety to achieve greater consistency with modern standards are important aspects of these reviews. The site licences and the site licence conditions make no reference to plants design lifetimes.

b) Basis of cost estimates

The cost data for the UK was obtained from the assessment of the cost to secure 10 years further operation for Bradwell Magnox station (from 40 to 50 years). The assessment was carried out at an early stage in the preparation of a PSR. Account was taken of the regulatory requirements associated with the PSR together with plant requirements to improve operational reliability and reduce maintenance cost. The data takes account of recent similar work completed at other Magnox NPPs in the UK. The scope of PLEX cost drivers reported is presented in Table 18.

6.3.12. United States of America

In 2001, nuclear power provided 20.35 % of all the electric power produced in the United States. The first operating license will expire in the year 2006; approximately 10 % will expire by the end of 2010 and more than 40 % will expire by the year 2015.

Table 18 Scope of PLEX cost drivers reported for NPP Bradwell — Magnox

Item	*Description*
1	**Safety upgrades to meet regulatory requirements**
1.1	Critical equipment & systems
1.1.1	Shutdown systems
1.1.2	Emergency Feedwater
1.1.3 1.1.4 1.1.5	Emergency Indication Centre Fire Protection Reactor Instrumentation
1.1.6	Other Instrumentation
1.1.7	Burst fuel can detection
1.1.8	Heating and Ventilation
1.1.9	Civil Structures
1.1.10	Seismic Modifications
1.1.11	Boiler Shell Inspection
1.1.12	Electrical Systems
1.2	Documentation
1.2.1	Safety re-evaluation
2	**Waste & spent fuel management**
2.1	Increased spent fuel storage
2.2	Fuel Ponds
3	**Other non safety and conventional system upgrades (improvements & up rate)**
3.1	Cooling water system replacement
3.2	Turbine refurbishment
3.3	Conventional cranes
3.4 3.5	Boiler steam/feed system Communications/Instrumentation
4	**Fuel cycle improvements**
4.1	Fuel cycle management
4.2	Cooling Ponds

a) Regulatory process [16]

In the United States the original plant life is established by the regulatory process. The Atomic Energy Act of 1954 limits the initial operating licenses of nuclear power plants to 40 years and allows these licenses to be renewed for another 20 years. Plant owners may apply to renew the license as early as 20 years or as late as 5 years before the expiration of the current license. The initial 40-year license term for nuclear power plants was selected on the basis of economic and antitrust considerations and not because of any technical limitations.

In 1991, NRC published safety requirements for license renewal as 10 CFR Part 54 and in 1995 amended this rule. The amended Part 54 establishes an efficient, tightly focused process that makes license renewal a safe, viable option. This revision stresses managing the effect of ageing rather than managing with ageing mechanisms. In revising the license renewal rule, the NRC recognized existing plant programs in inspection and maintenance. The new rule shifts the emphasis from identifying "aging mechanisms" to managing their effects on the plant. The rule changes were intended to ensure that important systems, structures and components will continue to perform their intended function during the 20-year period of extended operation.

The license renewal process and application requirements for commercial power reactors are based on two key principles:

- The current regulatory process, continued into the extended period of operation, is adequate to ensure that the current licensing basis of all currently operating plants provides and maintains an acceptable level of safety for extended operation, with the possible exception of the detrimental effects of aging on certain systems, structures, and components, and possibly a few other issues related to safety only during the period of extended operation, and

- Each plant's current licensing basis is required to be maintained during the renewal term.

The license renewal process requires that both a technical review of safety issues and an environmental review be performed for each application. NRC regulations, 10 CFR Part 54 and respectively 10 CFR Part 51, contain the requirements for these reviews. Public participation (through public meetings, public hearings, through publishing information provided by licensee and NRC evaluations & findings, etc.) is an important part of the license renewal process.

The license renewal application includes general information and technical information in compliance with 10 CFR Part 54. The general information contained in the license renewal application is much the same as that provided with the initial operating license application (10 CFR 54.17 & 54.19). The NRC regulations 10 CFR 54.21 require that each application for a renewal license for a nuclear plant include information related to the following:

- Technical Information (10 CFR 54.21): The applicant must provide the NRC an evaluation that addresses the technical aspects of plant aging and describes the ways those effects will be managed over the life of the nuclear plant. This includes the following information:

  - Integrated Plant Assessment

  - Current License Basis

  - Time-Limited Aging Analyses

  - Final Safety Analysis Report

- Technical Specifications (10 CFR 54.22): technical specification changes or additions, with justification, necessary to manage the effects of aging during the period of extended operation must be included in the license renewal application.

Each license renewal applicant must include a supplement to the environmental report, which contains an analysis of the plant's impact on the environment if allowed to continue operation beyond the initial license.

It is currently expected that license renewal will take about 30 months.

The first US electric utility to file an application with the NRC was Baltimore Gas and Electric Company. On April 10, 1998, the utility applied for a 20-year license extension for its two-unit Calvert Cliffs nuclear power plant. Unit 1's initial operating license will expire in 2014; Unit 2's in 2016. In March 2000 Nuclear Regulatory Commission approved the application for both Unit 1 and 2 after examining safety and environmental issues related to operations.

NRC granted also license renewal to:

- Duke Power for its three-unit Oconee Nuclear Station (May 2000)
- Entergy for its Arkansas Nuclear One 1 (June 2001)
- Southern Nuclear for its Edwin I. Hatch 1 & 2 (January 2002)

Applications to renew the license have been submitted also to NRC by Florida Power & Light Company (in 2000) for Turkey Point, Units 3 & 4; by Virginia Electric and Power Company (Dominion) (in 2001) for North Anna Units 1 & 2 and for Surry Units 1&2; by Duke Energy Corporation (in 2001) for Catawba, Units 1 & 2 and McGuire Units, 1 & 2; by Excelon Generation (in 2001) for Peach Bottom, Units 2 & 3; by Florida Power & Light Company (in 2001) for St. Lucie 1 & 2; and by Omaha Public Power District (in 2002) for Fort Calhoun .

There has been a remarkable change in perspective regarding the additional economic value that can be achieved by extending the operating licenses of nuclear power units.

Actually, further submittals are planned for:

- H. B. Robinson, Unit 2 - June 2002
- Ginna - July 2002
- V.C. Summer - August 2002
- Dresden, Units 2 and 3 - January-March 2003
- Quad Cities, Units 1 and 2 - January-March 2003
- Farley, Units 1 and 2 - September 2003
- Arkansas Nuclear One, Unit 2 - September 2003
- Nine Mile Point, Units 1 and 2 - October 2003
- D.C. Cook, Units 1 and 2 - November 2003
- Browns Ferry, Units 2 and 3 - December 2003

- Brunswick, Units 1 and 2 - January-March 2004
- Beaver Valley, Units 1 and 2 - September 2004 (Unit 2 requires exemption)
- Davis-Besse, Unit 1 - December 2004
- Pilgrim, Unit 1 - December 2004
- Susquehanna, Units 1 and 2 - January-March 2005
- Cooper - April 2005

b) Basis of cost driver estimates

PLEX cost drivers were provided for Fort Calhoun NPP. The cost data was obtained from the assessment of the costs to renew the 40-year term operation license for another 20-year term. Account was taken of the regulatory requirements associated with the license renewal together with plant requirements to improve operational reliability and reduce maintenance cost. The data takes account also information from several other plants in the USA. The scope of PLEX cost drivers reported is presented in Table 19.

Table 19. Scope of PLEX cost drivers for Fort Calhoun NPP (US)

Item	***Description***	***Remarks***
1	**Safety upgrades to meet regulatory requirements**	
1.1	Critical equipment & systems	
1.1.1	Steam generator	(1)
1.2	Documentation	
1.2.1	Safety re-evaluation	
1.2.2	Procedures	
3	**Waste & spent fuel management**	
3.2	Interim storage	
5	**Other non safety and conventional system upgrades (improvements & up rate)**	
5.3	Turbine up rate	
6	**Licensing process**	
12	**Environmental impact assessment**	(2)

Notes:

(1) The supply cost is the total cost of the replacement steam generators delivered to the NPP. The construction cost is the total cost to remove the old steam generators and install the replacement steam generators.

(2) Included in cost of safety assessment.

7. OVERVIEW OF THE PLEX/PLIM COSTS

7.1. General

While the main purpose of this document is to provide a methodology for the assessment of PLEX cost drivers, the authors have also attempted to estimate the direct cost impact of PLEX activities, assembling the data from a cross section of countries and reactor types.

Based on the responses to the questionnaire provided by the participant organizations (listed within Appendix IV), this section presents the PLEX/PLIM costs, for each of the plants reported. It should also be noted that cost data reported is limited to technical and regulatory related requirements specific to NPPs, as presented in section 5, and to cost basis for each NPP, as presented in section 6.

7.2. Cost data reported

Due to the competitive environment prevailing today in the electricity sector, and to be consistent with the confidentiality clauses, under which the information was released, the cost data are presented showing only the range for each reported item. The cost range was determined using quintiles.

A quintile is any of the four values of a variable, which divide a population into five groups, each containing one fifth of the total population. Quintiles calculation was made using PERCENTILE statistical function of MS EXCEL.

For example assuming that for one activity four cost data would be reported, and these costs would be C1=1; C2=5; C3=90; C4=175, then first quintile is Q1=3.4, the second one is Q2=22, Q3=73 and Q4=124. Then, reported costs would be presented as follows:

- C1<Q1 (C1 is in the range 0–Q1)
- C2>Q1 (C2 is in the range Q1-Q2)
- C3>Q3 (C3 is in the range Q3–Q4)
- C4>Q4 (C4 is greater than Q4)

Since respondents addressed the cost drivers sometimes differently, reported cost data are shown in a consolidated way to allow, where possible, a consistent presentation of data for similar activities from different plants. Activities reported under cost drivers “Safety upgrades to meet regulatory requirements”, and “Other non-safety and conventional system up - grades” were merged and grouped in “Process systems” and “Documentation”. Also activities reported under “ Wastes and spent fuel managements” and Fuel cycle improvements” were merged.

Tables 20 and 21 present summary and respectively detailed reported data as within first, second, third, forth or fifth intervals. The intervals were determined, using the quintile approach as described above, for all reported plants and reactor types (PWR, PHWR, WWER, BWR and Magnox).

It is important to note that the reported cost data came from various sources, with different backgrounds and philosophies. Therefore, data from different countries are not necessarily directly comparable and they have to be interpreted considering:

- ***Reported plants are of different types, size, design and vintage;***
- ***Different regulatory and environmental requirements, spent fuel and radwaste storage policy existing in the reporting countries;***
- ***Wide variations in scope of the work for each of the reported units;***
- ***The extent of modifications for given equipment is different from one unit to another unit;***
- ***Local conditions (operation history, the extent of replacements during the design life, accounting, labour, extension of the plant life considered, etc.);***
- ***Cost data are preliminary and with few exceptions they represent estimate costs; and***
- ***Basis of the reported cost data, presented in Section 6.***

Table 20. Summary of overall cost data reported

MUSD as of 1.01.2000

Item	Description	Cost range quintiles				BWR Japan 400 – 500 MW(e)	GCR Magnox UK Bradwell 123 MW(e)	PHWR Canada G-2 635 MW(e)	PHWR Canada Pick. A 515 MW(e)	PHWR India RAJ-1 187 MW(e)	PWR France CPU 1 900 MW(e)	PWR Japan 300 – 400 MW(e)	PWR Rep. of Korea Kori 1 556 MW(e)	PWR Nether-lands Borselle 449 MW(e)	PWR US Fort Calhoun 476 MW(e)	WWER Bulgaria Kozloduy 953 MW(e)	WWER Russian Fed. Kola 411 MW(e)
		1st Quintile (Q1)	2nd Quintile (Q2)	3rd Quintile (Q3)	4th Quintile (Q4)												
0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*
I	**Process systems**	**61.74**	**95.25**	**157.83**	**203.08**	**<Q1**	**>Q2**	**>Q4**	**>Q4**	**<Q1**	**>Q2**	**>Q4**	**>Q2**		**>Q3**	**>Q1**	**< Q1**
1	Reactor	4.30	9.66	27.30	127.25	<Q1		>Q4	> Q4	>Q3	>Q1	>Q3	>Q2			<Q1	
2	Reactor process systems	3.76	8.18	28.88	124.80	<Q1	>Q1		>Q2	> Q1	>Q3	>Q4	>Q3		>Q4		< Q1
3	Shut down systems	1.20	2.06	6.49	14.53	>Q3	>Q1		<Q1		>Q4	>Q2					
4	Turbo- generator	15.85	30.44	43.85	53.50	<Q1	>Q3		<Q1		>Q4	>Q4	>Q1		>Q2		
5	Emergency diesel generator	5.67	10.08	13.35	15.46				< Q1			<Q1	>Q4				
6	Steam/feed systems	1.39	10.85	15.14	22.83	>Q3	>Q2		> Q1			>Q4	>Q2				< Q1
7	Condenser & condensate	5.51	6.43	8.44	11.30			<Q1	> Q1		>Q4	>Q3	>Q2				
8	Circulating water system	7.19	7.37	8.95	11.94		>Q2					<Q1	>Q4				
9	Component cooling water system (CCW), service water system (SWS), heat exchangers	1.61	2.31	3.71	8.72	>Q1			> Q2			>Q3	>Q4				< Q1
10	Instrumentations and controls	2.96	5.92	7.16	7.83	>*Q4*	<Q1	>Q2	< Q1	> Q1		>Q2	>Q3			>Q4	
11	Electrical systems	0.96	3.91	5.88	7.46		>Q3	>Q4	> Q1	<Q1						>Q3	< Q1

Table 20. (cont.)

0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*
12	Miscellaneous	3.77	5.89	10.19	35.62	<Q1	>Q3	>Q2	> Q3	>Q1	>Q4	<Q1	>Q1			>Q4	> Q2
II	**Documentation (safety r evaluation)**	**1.49**	**2.41**	**7.01**	**8.11**		**>Q3**	**>Q4**	**< Q1**					**>Q2**	**>Q2**		**< Q1**
III	**Maintaining expertise (training)**	*	*	*	*				*								
IV	**Environmental impact assessment**	**2.06**	**4.02**	**5.66**	**6.98**				**> Q4**				**>Q2**	**<Q1**			
V	**Public acceptance**	**1.17**	**1.86**	**5.77**	**12.88**			**>Q2**					**>Q4**	**<Q1**			
VI	**Fuel cycle improvements, waste and spent fuel management**	**1.61**	**6.28**	**12.34**	**17.02**		**>Q4**	**<Q1**	**> Q3**				**<Q1**	**>Q1**	**>Q4**		**> Q2**
VII	**Licensing process**	**2.58**	**4.20**	**6.09**	**8.25**	**>Q4**		**<Q1**	**> Q3**			**>Q4**	**>Q1**		**>Q2**		**< Q1**
VIII	**O&M review**	**13.94**	**16.52**	**19.11**	**21.69**				**<Q1**							**>Q4**	
IX	**Operation spare assessment**	**6.63**	**9.28**	**11.93**	**14.59**				**< Q1**								**> Q4**
X	**Decommissioning**	*	*	*	*												*
XI	**Overall risk assessment**	**16.77**	**28.53**	**40.30**	**52.06**			**>Q4**					**<Q1**				
X	**Other remaining costs**	**31.05**	**37.10**	**49.78**	**69.08**			**>Q4**		**>Q2**			**<Q1**				
	TOTAL	**71.29**	**114.43**	**174.08**	**320.12**	**<Q1**	**>Q2**	**>Q4**	**> Q4**	**>Q1**	**>Q2**	**>Q4**	**>Q3**	**<Q1**	**>Q3**	**>Q1**	**< Q1**
	TOTAL PER KWe [$/KWe]	**121.81**	**252.20**	**412.66**	**680.48**	**>Q1**	**>Q4**	**>Q3**	**> Q4**	**>Q2**	**>Q1**	**>Q4**	**>Q2**	**<Q1**	**>Q3**	**<Q1**	**< Q1**

Legend
; "*" = sole source data
"Blank cell" = no data provided

Table 21. Overall cost data reported

MUSD as of 1.01.2000

Item	Description	Cost range quintiles				BWR Japan 400 – 500 MW(e)	GCR Magnox UK Bradwell 123 MW(e)	PHWR Canada G-2 635 MW(e)	PHWR Canada Pick. A 515 MW(e)	PHWR India RAJ-1 187 MW(e)	PWR France CPU 1 900 MW(e)	PWR Japan 300 – 400 MW(e)	PWR Rep. of Korea Kori 1 556 MW(e)	PWR Nether-lands Borselle 449 MW(e)	PWR US Fort Calhoun 476 MW(e)	WWER Bulgaria Kozloduy 953 MW(e)	WWER Russian Fed. Kola 411 MW(e)
		1st Quintile (Q1)	2nd Quintile (Q2)	3rd Quintile (Q3)	4th Quintile (Q4)												
0	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***13***	14	***15***	***16***	***17***
I	Process systems	61.74	95.25	157.83	203.08	<Q1	>Q2	>Q4	>Q4	<Q1	>Q2	>Q4	>Q2		>Q3	>Q1	< Q1
1	Reactor	4.30	9.66	27.30	127.25	<Q1		>Q4	> Q4	>Q3	>Q1	>Q3	>Q2			<Q1	
1.1	Reactor vessel (head included)	3.65	5.25	6.26	11.34	<Q1					>Q3	>Q4	>Q1				
1.2	Reactor vessel internals	12.67	19.82	26.96	34.11							>Q4	<Q1				
1.3	Reactor retubing (PHWR)	80.43	141.66	184.64	209.37			>Q2	>Q4	<Q1							
1.4	RPV integrity	*	*	*	*											*	
2	Reactor process systems	3.76	8.18	28.88	124.80	<Q1	>Q1		>Q2	> Q1	>Q3	>Q4	>Q3		>Q4		< Q1
2.1	Steam generator	13.09	16.16	103.61	111.99		<Q1		>Q1		>Q4	>Q2	>Q2		>Q4		
2.2	Pressuriser	5.15	7.81	10.48	13.14							>Q4	<Q1				
2.3	Reactor cooling pump	8.39	9.15	9.90	10.66							>Q4	<Q1				
2.4	Reactor cooling system piping	6.68	8.01	9.34	10.67						>Q4		<Q1				
2.5	Reactor systems including heat exchangers	*	*	*	*					*							
2.6	Reactor recirculation pump motor	*	*	*	*	*											
2.7	Reactor recirculation pump (main shaft, impeller)	*	*	*	*	*											
2.8	Moderator heat exchanger	*	*	*	*				*								
2.9	Residual heat exchanger	1.51	2.23	2.95	3.67	<Q1						>Q4					

Table 21. (cont.)

0	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***13***	14	***15***	***16***	***17***
2.10	Residual heat removal pump	*	*	*	*							*					
2.11	Biological shield cooling upgrade	*	*	*	*				*								
2.12	Emergency core cooling system	1.25	1.47	1.81	2.27				>Q2	>Q4							< Q1
2.13	Reactor core isolation cooling turbine	*	*	*	*	*											
3	Shut down systems	1.20	2.06	6.49	14.53	>Q3	>Q1		<Q1		>Q4	>Q2					
3.1	Control rods	14.53	16.79	19.04	21.30	<Q1					>Q4						
3.1.1	Guide thimble pins replacement (including thimble tube replacement)	*	*	*	*						*						
3.1.2	Monitoring	*	*	*	*						*						
3.1.3	Drive mechanism	4.56	6.49	8.42	10.35	>Q4						<Q1					
4	Turbo- generator	15.85	30.44	43.85	53.50	<Q1	>Q3		<Q1		>Q4	>Q4	>Q1		>Q2		
4.1	Turbine	7.00	15.36	38.71	47.53	<Q1	>Q4				>Q3		>Q1				
4.1.1	LP turbine	9.53	18.77	28.02	37.26						>Q4		<Q1				
4.1.2	HP turbine	*	*	*	*								*				
4.2	Turbine uprate	*	*	*	*										*		
4.3	Generator/exciter	5.87	7.36	10.31	14.74	<Q1					>Q2		>Q4				
5	Emergency diesel generator	5.67	10.08	13.35	15.46				< Q1			<Q1	>Q4				
6	Steam/feed systems	1.39	10.85	15.14	22.83	>Q3	>Q2		> Q1			>Q4	>Q2				< Q1
6.1	Feedwater system	4.89	9.29	15.50	18.26	>Q4			< Q1			>Q3	>Q1				
6.1.1	Feedwater heaters	10.89	12.99	15.10	17.20	>Q4						<Q1					
	High pressure heater	*	*	*	*							*					
	Low pressure heater	*	*	*	*							*					
6.1.2	Feedwater pump	2.42	2.47	2.53	2.58							>Q4	<Q1				
6.1.3	Charging pump	*	*	*	*								*				
6.1.4	Auxiliary feedwater pump	*	*	*	*								*				

Table 21. (cont.)

0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
6.1.5	Deaerator	*	*	*	*							*					
6.1.6	Regenerative heat exchanger	*	*	*	*							*					
6.2	Steam system	2.08	3.57	4.50	4.89	>Q2						>Q4	<Q1				
6.2.1	Moisture separator and reheater	2.46	3.16	3.87	4.57	<Q1						>Q4					
6.2.2	Main steam safety/safety relief valve	0.83	1.06	1.30	1.53	>Q4							<Q1				
6.2.3	Main steam isolation valve actuator	*	*	*	*	*											
6.3	Emergency feedwater system	*	*	*	*		*										
6.4	Emergency auxiliary SG make-up system	*	*	*	*												*
6.5	Piping (MS, FW etc)	*	*	*	*								*				
7	Condenser & condensate	5.51	6.43	8.44	11.30			<Q1	> Q1		>Q4	>Q3	>Q2				
7.1	Condenser retubing	3.96	5.24	6.98	9.68			>Q1			>Q4	>Q3	<Q1				
7.2	Condensate pump	1.89	2.03	2.16	2.30							<Q1	>Q4				
7.3	Condenser I/O piping	*	*	*	*								*				
7.4	Gland steam condenser	*	*	*	*							*					
8	Circulating water sys.	7.19	7.37	8.95	11.94		>Q2					<Q1	>Q4				
8.1	Circulating water pump	7.05	7.08	7.10	7.13							<Q1	>Q4				
8.2	Circulating system (except pumps)	*	*	*	*								*				
9	Component cooling water system (CCW), service water system (SWS), heat exchangers	1.61	2.31	3.71	8.72	>Q1			> Q2			>Q3	>Q4				< Q1
9.1	CCW piping, heat exchangers, valves	3.16	4.57	5.77	6.78	<Q1						>Q2	>Q4				
9.2	Service water system	1.67	2.34	4.12	7.00				> Q2				> Q4				< Q1
9.3	Auxiliary boiler	*	*	*	*								*				

Table 21. (cont.)

0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	14	*15*	*16*	*17*
9.4	Heat exchangers (LP, MP, HP)	*	*	*	*								*				
10	Instrumentations and controls	2.96	5.92	7.16	7.83	>Q4	<Q1	>Q2	< Q1	> Q1		>Q2	>Q3			>Q4	
10.1	Station computers	4.16	6.67	6.93	7.37	>Q4		>Q1	< Q1			>Q3					
10.2	Process control/protection system	*	*	*	*								*				
10.3	Nuclear instrumentation system (ex-core)	*	*	*	*								*				
10.4	Instrument air system except piping	*	*	*	*								*				
10.5	Manifold, sensing tube	*	*	*	*								*				
10.6	Reactor instrumentation	*	*	*	*		*										
10.7	Other instrumentation (safety related)	*	*	*	*		*										
10.8	Communication /instrumentation (non-safety)	*	*	*	*		*										
10.9	Post TMI accident actions	*	*	*	*								*				
10.10	Control cable	*	*	*	*								*				
10.11	Reactor core control improvement	*	*	*	*											*	
10.12	Replacement of safety related I&C equipment and implementation of diagnostic systems	*	*	*	*											*	
11	Electrical systems	0.96	3.91	5.88	7.46		>Q3	>Q4	> Q1	<Q1						>Q3	< Q1
11.1	Selective cable replacement	*	*	*	*			*									
11.2	Replacement of safety related electrical equipment	*	*	*	*											*	
11.3	Electrical overhauls	*	*	*	*				*								
11.4	Main power output (transformer)	*	*	*	*				*								

Table 21. (cont.)

0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	14	*15*	*16*	*17*
11.5	Reliable power supply for 2nd group of consumers	*	*	*	*												*
12	Miscellaneous	3.77	5.89	10.19	35.62	<Q1	>Q3	>Q2	> Q3	>Q1	>Q4	<Q1	>Q1			>Q4	> Q2
12.1	Building and structures	0.32	0.53	1.09	2.00		>Q4			> Q2							< Q1
12.2	HVAC	0.64	0.72	0.80	0.87		*		> Q4								
12.2	Ducts (non safety and conventional)	*	*	*	*								*				
12.3	Anchoring (piping supports - safety related)	*	*	*	*						*						
12.4	Lifting equipment improvement (safety related)	*	*	*	*						*						
12.5	Conventional cranes (non safety)	*	*	*	*		*										
12.6	Fuel handling improvements (safety related) including fuelling machine systems	1.93	2.25	2.58	2.90				> Q4		*						
12.7	Fire protection improvement	0.26	1.31	6.33	7.53		>Q1		> Q2		>Q4		<Q1			>Q4	< Q1
12.8	Improvement of periodic tests (safety related)	*	*	*	*						*						
12.9	PLIM "small modifications"- not included above (safety related)	*	*	*	*						*						
12.10	PLIM "small modifications"- not included above (non safety and conventional)	*	*	*	*						*						
12.11	Mechanical systems	*	*	*	*					*							
12.12	Airlock	*	*	*	*							*					
12.13	High pressure injection turbine	*	*	*	*	*											
12.14	Containment	*	*	*	*												*
12.15	Emergency indication centre	*	*	*	*		*										

Table 21. (cont.)

0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	14	*15*	*16*	*17*
12.16	Burst fuel can detection	*	*	*	*		*										
12.17	Simulator upgrade	*	*	*	*					*							
12.18	Regulation provision	*	*	*	*			*									
12.19	Seismic modifications, requalifications, reinforcements and improvements	1.87	2.24	3.60	5.93		>Q2		< Q1							> Q4	
12.20	Installation of new system to improve the safety and replacement of safety related equipment	*	*	*	*											*	
12.21	Environmental qualification	*	*	*	*				*								
12.22	Reduction of severe core damage frequency	*	*	*	*				*								
12.23	Replace class II MG sets with inverters	*	*	*	*				*								
12.24	Accident localization system	*	*	*	*												*
12.25	Valve refurbishment (AOV/MOV)	*	*	*	*				*								
12.26	Relief valve refurbishment	*	*	*	*				*								
12.27	Pump maintenance	*	*	*	*				*								
12.28	Screenhouse upgrade	*	*	*	*				*								
12.29	Vapour recovery system upgrade	*	*	*	*				*								
12.30	Assessment of residual life of equipments and replacements where required	*	*	*	*									>Q2			*

Table 21. (cont.)

II	**Documentation (safety re-evaluation)**	**1.49**	**2.41**	**7.01**	**8.11**		**>Q3**	**>Q4**	**< Q1**					**>Q2**	**>Q2**		**< Q1**
0	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***13***	14	***15***	***16***	***17***
III	**Maintaining expertise (training)**	*	*	*	*				*								
IV	**Environmental impact assessment**	**2.06**	**4.02**	**5.66**	**6.98**				**> Q4**				**>Q2**	**<Q1**			
V	**Public acceptance**	**1.17**	**1.86**	**5.77**	**12.88**			**>Q2**					**>Q4**	**<Q1**			
VI	**Fuel cycle improvements, waste and spent fuel management**	**1.61**	**6.28**	**12.34**	**17.02**		**>Q4**	**<Q1**	**> Q3**				**<Q1**	**>Q1**	**>Q4**		**> Q2**
1	Interim storage	*	*	*	*									>Q1	*		
2	Increased spent fuel storage	2.10	2.63	3.24	4.45		<Q1		> Q4								> Q3
3	Increased spent fuel disposal	6.98	7.39	7.80	8.21				< Q1								> Q4
4	Fuel ponds	*	*	*	*		*										
5	Spent fuel pit cooling system	*	*	*	*								*				
6	Isolation door between spent fuel reception bay and storage bay	*	*	*	*			*									
7	Fuel cycle management	*	*	*	*		*										
8	Cooling ponds	*	*	*	*		*										
VII	**Licensing process**	**2.58**	**4.20**	**6.09**	**8.25**	**>Q4**		**<Q1**	**> Q3**			**>Q4**	**>Q1**		**>Q2**		**< Q1**
VIII	**O&M review**	**13.94**	**16.52**	**19.11**	**21.69**				**<Q1**							**>Q4**	
IX	**Operation spare assessment**	**6.63**	**9.28**	**11.93**	**14.59**				**< Q1**								**> Q4**
X	**Decommissioning**	*	*	*	*												*
XI	**Overall risk assessment**	**16.77**	**28.53**	**40.30**	**52.06**			**>Q4**					**<Q1**				

Table 21. (cont.)

XII	**Other remaining costs**	**31.05**	**37.10**	**49.78**	**69.08**			**>Q4**		**>Q2**			**<Q1**				
1	Project administration	*	*	*	*			*									
0	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***13***	14	***15***	***16***	***17***
2	Operation, maintenance & administration	29.31	38.24	47.17	56.10			>Q4		<Q1							
3	Power	*	*	*	*					*							
4	Miscellaneous (fuel, D2O, IDC, etc.)	*	*	*	*					*							
5	New fuel for start-up after refurbishment	*	*	*	*			*									
6	Pre-project	*	*	*	*			*									
	TOTAL	**71.29**	**114.43**	**174.08**	**320.12**	**<Q1**	**>Q2**	**>Q4**	**> Q4**	**>Q1**	**>Q2**	**>Q4**	**>Q3**	**<Q1**	**>Q3**	**>Q1**	**< Q1**
	TOTAL PER KWe [$/KWe]	**121.81**	**252.20**	**412.66**	**680.48**	**>Q1**	**>Q4**	**>Q3**	**> Q4**	**>Q2**	**>Q1**	**>Q4**	**>Q2**	**<Q1**	**>Q3**	**<Q1**	**< Q1**

Legend

; "*" = sole source data
"blank cell" = no data provided

8. CONCLUSIONS

This section summarizes the results obtained during the report preparation. Particularly, the following topics are covered:

- General observations on methodology developed and cost collected.
- Applicability of the developed methodology and of collected costs in approaching PLEX costing.

i. The study provides an overview of the process to decide on PLEX with a focus on economic assessment; identifies and describe the PLEX cost drivers; presents the overall framework in which the cost drivers were identified; contains a methodology that can be used for a systematic approach of PLEX cost input data to be further used in PLEX economic assessment; presents PLEX cost data collected and describes the basis of the collected costs.

ii. The cost data provided during the survey covers only 12 of the 13 cost drivers described and identified. It must be noted that about 80% of the total cost reported can be attributed to the first two cost drivers.

- Safety upgrades to meet regulatory requirements
- Other non-safety and conventional system upgrades
- Environment impact assessment
- Maintaining expertise
- Public acceptance
- Radioactive wastes and spent fuel management
- Decommissioning
- Licensing process
- Operating and maintenance review
- Operating spares and consumables assessment
- Fuel cycle improvements
- Overall risk assessment

iii. The majority of cost data provided are within the capital cost category.

iv. The study confirms the diversity of national and regulatory approaches to PLEX/ PLIM within the reporting countries. It is difficult to make a distinction between PLEX and PLIM.

v. Based on the cost data, it was recognized that PLEX costs were highly dependent on specific conditions related to each country such as: state of maturity of PLEX; design of the plant; NPP operating history including aging conditions; condition of the critical SSCs; regulatory requirements; extent of backfitting; full or partial replacement of components; refurbishment for PLIM versus refurbishment for PLEX; local conditions (e.g. shop versus onsite refurbishment); accounting methodologies; actual versus estimated cost.

vi. The report can be used for a general understanding of the various PLEX cost drivers. Also the methodology developed can assist the staff involved in preparing cost estimates to be used as input data for PLEX economic assessment.

vii. Given the current trend to deregulation of the electricity market there is a business window PLEX. For a large part of the existing NPPs, PLEX option will become a more preferred option.

Appendix I

GENTILLY 2 LIFE EXTENSION CASE STUDY [17]

Gentilly 2 is a PHWR NPP installed on the shores of the St. Lawrence River, with a nominal capacity of 675 MW(e). It is operated by Hydro-Québec a publicly owned company with a single shareholder, the Québec Government.

The design life of the 380 reactor pressure tubes is 30 years at an average capacity factor of 80%. However, it appears that the service life of the pressure tubes might be slightly shorter. As the Gentilly 2 pressure tubes have reached the halfway point of their design life, Hydro-Québec will have to choose in the near future between embarking on a second life cycle for its sole nuclear power plant or decommissioning it and replacing it with a non nuclear alternative capable of providing comparable energy and power to the grid.

For Gentilly-2, a PLEX review process begun about three years ago. As it was known since the early design, the fuel channels have a residual life shorter than the plant. Therefore, should a life extension decision be made, the refurbishment for PLEX have to be implemented in 2008–2009. A 25-year life extension is possible.

The following approach was taken: in a first step, it was evaluated if Gentilly 2 refurbishment is interesting from a purely economical perspective. If so, a detailed technical assessment of the plant's condition has to be performed, based on a 20-year life extension after 2013, together with a more accurate cost evaluation. The first step is summarized below:

(1) An analysis was performed to evaluate economically what would be the best approach for a continued 675 MW(e) nuclear generation at the end of the service life of the current pressure tubes. Three scenarios were costed:

- At the end of the pressure tubes' life, stop the generation, change all the tubes, refurbish the rest of the plant and restart.

- A few years before the end of the pressure tubes' life, replace annually a portion of the pressure tubes in order to have them all changed on time, making sure that Gentilly 2 would be on power during each Hydro-Québec peak winter period. The rest of the plant would also be refurbished

- On an appropriate schedule, build another similar CANDU 6 in order to have it ready to be on grid at the end of Gentilly 2 pressure tubes' life.

Three categories of issues were studied and costed: station structures, systems and components (only a specific list of equipment issues), a list of twenty-four Regulatory issues and routine costs. More than eleven hundred variables were collected, all with their respective probability distribution. These were integrated into one computer model, and probable costs for the years 1999 to 2033, all adjusted to the 1998 value of the Canadian dollar were calculated for each of the three scenarios. The results show that replacement by a new unit would cost significantly more than the other two scenarios and the one time refurbishment is the cheapest approach of the three, with the least cost uncertainty when compared to the modular approach.

(2) The cost of nuclear life extension project was compared, with alternative power and energy, which would still be available for commissioning at that time. Two options were evaluated:

i. Life extension of the nuclear plant in a timely manner (year 2008)

ii. Abandonment of the nuclear option in 2008, and replacement of the generation by new hydroelectric plant, or new combine cycle natural gas turbine (CCNGT).

While both options involve operating Gentilly 2 until 2008, the first one is followed by a refurbishment period of 18 months and continued operation until 2033 (for a total station service life of 50 years), and followed by a final shutdown and decommissioning. The second option considers that, in 2008, there would be the final shutdown, followed by the decommissioning cycle, and the beginning, in 2009, of generation by a new non nuclear unit until 2033. The residual value of that new unit, if any, is taken into consideration in the economical model.

For each project were considered and incorporated in the model: a predetermined rate of return for the direct investment made by Hydro-Québec; project risk; a service life of 50 years for the hydro plants; an efficiency of 60% and the investment and operating costs as for the existing ones, for CCNGT; capacity factor correction. The decommissioning costs were added to the non-nuclear alternatives discounted in 2008. The same costs, discounted in 2033, were added to the Gentilly life extension. Three different sources of information were used for natural gas price, each with a high, a low and a most probable cost for future years. For the final comparison a mean value for the three low estimations and the same for the high and most probable values were taken into account. Finally, all costs were discounted in 2009. Detailed results are provided in Figure AI.1 for each of the three options. Results are shown in percentage of the total investment required to refurbish Gentilly 2.

At this stage, the overall result is that the Gentilly 2 life extension project is interesting when compared to the two hydroelectric alternatives, mainly due to the high costs of the transportation lines that must be built, those plants being so far away from the main customers in Québec. The Gentilly 2 life extension project is also interesting when compared to the CCNGT alternative when using the reference or high natural gas cost prediction; however, a doubt exists when the low gas cost evaluation is considered.

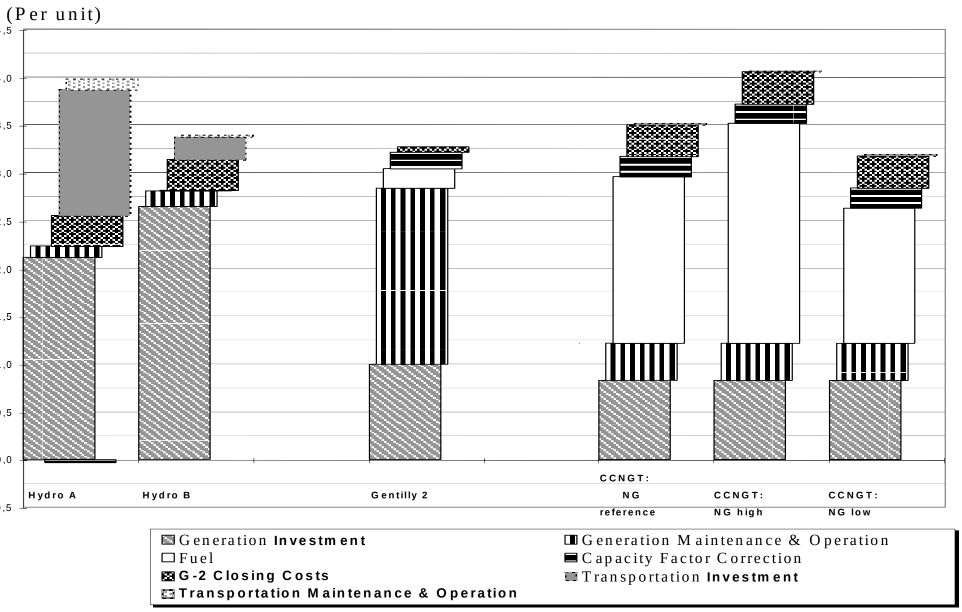


FIG. AI-1. Comparison between G-2 PLEX and replacement by non-nuclear project [17].

Appendix II

GENERIC LIST OF CRITICAL ITEMS FOR A PWR/PHWR NPP

The items listed below identify critical structures and components with emphasis on Plant Life Management for a PWR/PHWR NPP.

(1) Reactor vessel
(2) In-core thimble
(3) Bimetallic connections
(4) Inconel component parts
(5) Fuel Channels
(6) Steam Generators (Boilers)
(7) Large Nuclear Class Heat Exchangers
(8) Nuclear Class Piping & Supports
(9) Civil Engineering Nuclear Island
(10) Turbine
(11) Generator or Alternator
(12) Computers (including Instrumentation and Control Components)
(13) Containment Structure
(14) Reactor Pit Joint
(15) Control Rod Command Line
(16) Electric Cables
(17) BOP Piping
(18) Pressurizer
(19) Reactor Coolant Pumps
(20) Nuclear Class Pumps
(21) Air cooler
(22) Condenser
(23) Spent Fuel Bay
(24) Large Vessels
(25) Airlock
(26) Feedwater Heaters
(27) Separator/Reheater
(28) Circulating Pump Reducer
(29) Feed Pump
(30) Valves
(31) Diesel – Power electronics

Appendix III

COST DRIVER MATRIX

Item	Description	Categ ory	R&D	Enginee ring	Supply	Constructi on		Operati ons	Maintena nce	Others	Total	Prob. [%]	Expected cost	Remarks
			L	**L**	**M**	**L**	**M**	**L**	**L**		**[a]**	**[b]**	**[a]*[b]**	
0	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***13***	***14***
1	**Safety upgrades to meet regulatory requirements**													
1.1	Critical equipment & systems													
1.1.1	Steam Generator													
1.1.2	…………………………….													
1.2	Documentation													
1.2.1	Safety re-evaluation													
1.2.2	Procedures													
1.2.3	…………………..													
1.3	……………………													
2	**Other non safety and conventional system upgrades (improvements & up rate)**													
2.1	Selective cable replacement													
2.2	Condenser replacement													
2.3	Turbine up rate													
2.4	……………													
3	**Management programs and processes**													
3.1	……….													
4	**Environmental impact assessment**													

0	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*
	4.1….													
5	**Maintaining expertise**													
5.1														
6	**Public acceptance**													
6.1														
7	**Radioactive waste & spent fuel management**													
7.1	Increased spent fuel storage													
7.2	Interim storage													
7.3	Create a new spent fuel storage site													
8	**Decommissioning related**													
8.1	……………….													
9	**Licensing process**													
9.1	……………..													
10	**O&M review**													
10.1	…………………													
11	**Operating spares assessment**													
11.1	……………………													
12	**Fuel cycle improvements**													
12.1	Fuel cycle management													
13	**Costs for implementing the PLEX projects**													
13.1	………………													
14	**Overall risk assessment**													
14.1	…………………..													
15	**Other remaining costs**													
15.1	………………….													

Legend: L = labour costs; M = material costs

Appendix IV

REPORTING ORGANIZATIONS

Armenia	Department of Atomic Energy, Ministry of Energy, 2, Government House, Republic Square, Yerevan
Bulgaria	Kozloduy NPP, 3321 Kozloduy
Canada	Hydro Quebec, Centrale nucléaire Gentilly-2, 4900, Boul. Bécancour, 5th floor, Bécancour (Québec)
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France	Electricité de France, Pôle Industrie — site Cap Ampère — 1, place Pleyel - 93282 Saint Denis Cédex
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Netherlands	Elektriciteits Productiemaatschappij Zuid, PO Box 130, 4380 AC Vlissingen
Russian Federation	ROSENERGATOM, Ordynka 26, Moscow 113180
South Africa	ESKOM, NPP Koeberg, Melkbosstrand, Cape, Private Bag X 10, 7440 Kernkrag
United Kingdom	BNFL Magnox Generation, Berkeley Centre, Berkeley Glos. GL 13 9PB
United States of America	Omaha Public Power District, Fort Calhoun Station, PO Box 399, Fort Calhoun, NE 68023

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ABBREVIATIONS

AOV	air operated valves
BWR	boiling water reactor
CANDU	Canadian deuterium uranium (PHWR)
CCW	circulating (condenser) cooling water
CRDM	control rod driving mechanism
CRIEPI	Central Research Institute of Electric Power Industry (Japan)
DCC	digital computer controller
DG	Diesel generator
EA	each
ECCS	emergency core cooling system
ECIS	emergency core injection system
EMCCR	en masse coolant channel replacement
EPS	emergency power supply
FSAR	Final Safety Analysis Report
FW	feed water
GCR	gas cooled reactor
HP	high pressure
HPECI	high pressure emergency core injection
HV	high voltage
HVAC	heating, ventilation, air conditioning
I&C	instrumentation and control
IDC	interests during construction
LOCA	loss of coolant accident
LP	low pressure
MG	motor generators
MP	medium pressure
MOV	motor (electric) operated valves
NPP	nuclear power plant
NSSS	nuclear steam supply system
O&M	operation and maintenance
PHWR	pressurized heavy water reactor
PLEX	plant lifetime extension

PLIM	plant lifetime management
PSA	probabilistic safety assessment
PSR	periodic safety review
PWR	pressurized water reactor
RAPS	Rajasthan nuclear power plant
RCS	reactor cooling system
R&D	research and development
RPV	reactor pressure vessel
SG	steam generator
SSC	systems, structures, or components
SWS	service water system
WWER	water cooled, water moderated energy reactor

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