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ECONOMIC ASSESSMENT OF THE LONG TERM OPERATION OF NUCLEAR POWER PLANTS: APPROACHES AND EXPERIENCE

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The Agency’s Statute was approved on 23 October 1956 by the Conference on the Statute of the IAEA held at United Nations Headquarters, New York; it entered into force on 29 July 1957. The Headquarters of the Agency are situated in Vienna. Its principal objective is “to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world’’.

IAEA NUCLEAR ENERGY SERIES No. NP-T-3.25

ECONOMIC ASSESSMENT OF THE LONG TERM OPERATION OF NUCLEAR POWER PLANTS: APPROACHES AND EXPERIENCE

INTERNATIONAL ATOMIC ENERGY AGENCY
VIENNA, 2018

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email: sales.publications@iaea.org
www.iaea.org/books

Printed by the IAEA in Austria
November 2018
STI/PUB/1813

IAEA Library Cataloguing in Publication Data

Names: International Atomic Energy Agency.
Title: Economic assessment of the long term operation of nuclear power plants : approaches and experience / International Atomic Energy Agency.
Description: Vienna : International Atomic Energy Agency, 2018. | Series: IAEA nuclear energy series, ISSN 1995–7807 ; no. NP-T-3.25 | Includes bibliographical references.
Identifiers: IAEAL 18-01194 | ISBN 978–92–0–104218–7 (paperback : alk. paper)
Subjects: Nuclear power plants. | Nuclear energy — Economic aspects. | Cost effectiveness.
Classification: UDC 621.039.577:338.514 | STI/PUB/1813

FOREWORD

One of the IAEA's statutory objectives is to "seek to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world." One way this objective is achieved is through the publication of a range of technical series. Two of these are the IAEA Nuclear Energy Series and the IAEA Safety Standards Series.

According to Article III.A.6 of the IAEA Statute, the safety standards establish "standards of safety for protection of health and minimization of danger to life and property". The safety standards include the Safety Fundamentals, Safety Requirements and Safety Guides. These standards are written primarily in a regulatory style, and are binding on the IAEA for its own programmes. The principal users are the regulatory bodies in Member States and other national authorities.

The IAEA Nuclear Energy Series comprises reports designed to encourage and assist research and development on, and application of, nuclear energy for peaceful uses. This includes practical examples to be used by owners and operators of utilities in Member States, implementing organizations, academia, and government officials, among others. This information is presented in guides, reports on technology status and advances, and best practices for peaceful uses of nuclear energy based on inputs from international experts. The IAEA Nuclear Energy Series complements the IAEA Safety Standards Series.

This publication shares operational experience and lessons learned from techno-economic assessments of the management cost drivers related to the long term operation of nuclear power plants, the external cost drivers influencing plant life management of plants in a changing electricity market and the technical cost drivers strengthening safety upgrades to reflect the lessons learned from the accident at the Fukushima Daiichi nuclear power plant.

This publication highlights the need for further studies on technical cost drivers and economic assessments, in order to better define the cost boundaries of the long term operation of nuclear power plants. It shows how project risks are identified and estimated, and how cost–benefit analyses are conducted and presented to stakeholders in support of a long term operation decision. In addition, this publication provides the data to update the relevant IAEA software to reflect the latest technical feedback with respect to assumptions, methodology, processing and output.

The IAEA received generous support from several Member States, in the form of experts and technical content, for this publication and wishes to express its appreciation for their valuable contributions. It is particularly grateful to the members of the working group, who provided the main structure, recommendations and comments relating to the purpose, content and form of this report. In addition, the IAEA wishes to express its gratitude to all the experts who participated in the drafting and review of this publication and to all those who contributed to the specific cost items and technical data on long term operation.

The IAEA officers responsible for this publication were K.-S. Kang and A.I. Jalal of the Division of Nuclear Power and the Division of Planning, Information and Knowledge Management

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1. INTRODUCTION

1.1. BACKGROUND

The history of nuclear power generation has undoubtedly been influenced by the few accidents that have occurred in the years since its introduction. Between the Chernobyl accident (in April 1986) and the early 2000s, the increased cost of new nuclear power plants (NPPs) made new building less attractive. Nuclear power capacity was maintained not by new construction, but by the enhancement of existing plants, through power upgrades, and through the continued operation of the first generation of NPPs that had reached the end of their originally licensed operating life. Long term operation of these plants became attractive because their capital investments had depreciated over their years of operation.

Beginning in 2000, technological advances, including the introduction of the third generation of NPP designs, aroused interest in nuclear power in many Member States. Nuclear power was reconsidered as a competitive energy source to provide steady baseload power in countries with an established energy mix. In parallel, several countries, new to nuclear power generation, were also expressing interest in a first nuclear plant project.

Owners of NPPs that were reaching the end of their licensed life were faced with the choice of decommissioning or refurbishing their plants to prolong operation beyond their originally planned service life. The latter strategy allowed them to preserve the country's nuclear generation share and optimize the return on their investment.

After the nuclear accident at the Fukushima Daiichi plant, construction of NPPs slowed down and new projects were delayed. The world's total nuclear generating capacity has remained roughly steady, even though many operating NPPs are approaching the end of their originally planned design life, because operators have considered lifetime extension a viable option for maintaining their share of steady baseload power generation.

Understanding the optimal generation mix for a region or a country involves a number of complex technical, political and socioeconomic issues. In 1999 and 2002, the IAEA issued publications on cost drivers [1, 2] in the context of economic studies on NPPs. These reports described the commonalities in all cases associated with long term operation (LTO) in evaluating technical and economic feasibility options and in licensing processes. In addition, the IAEA has also made available to Member States a computer tool to help in evaluating the economic competitiveness of the LTO of NPPs. Other reports on LTO from the IAEA include a report on plant life management (PLiM) models for the LTO of NPPs [3] and a feasibility study guide for LTO assessments [4].

Lessons learned from heavy equipment replacement projects, modernizations of main control rooms, large scale plant refurbishments, power uprate projects, licensing renewal applications and stress tests or safety reviews conducted following the Fukushima Daiichi accident have provided new input to cost–benefit assessments of LTOs.

From the beginning of the new millennium, changes to both the energy and financial markets have occurred in various parts of the world leading to the deregulation of electricity markets. In addition, the sharp drop in the price of natural gas, the reduction in regional electricity demand and the surge of subsidized and/or mandated renewable energy generation have profoundly influenced the economic and financial models of the electricity market.

Accordingly, in this publication the cost drivers for the assessment of NPPs for LTO are revisited in order to address the new conditions of the energy market and the lessons learned from operational experience. The latest approaches and experience with economic assessment of the LTO of NPPs are reviewed. Two terms central to the main topic of these guidelines are introduced:

— PLiM can be defined as the integration of ageing management and economic planning to optimize NPP investments in favour of safety, commercial profitability and competitiveness, while ensuring a reliable supply of electrical power. When PLiM technologies[1] are properly applied, they can achieve the following results:
  - Maintain a high level of safety;
  - Optimize the operation, maintenance and service life of structures, systems and components (SSCs);

[1] There are other definitions of PLiM related to its multifaceted optimization capabilities. The Electric Power Research Institute in the United States of America produced a glossary of common ageing and PLiM terms. This glossary is being further developed by the Nuclear Energy Agency of the Organisation for Economic Co-operation and Development (OECD/NEA) and will likely become the basic communication tool in this field.

  - Maintain an optimized performance level;
  - Maximize the return on investment over the service life of the NPP;
  - Provide NPP owners with the optimal preconditions for achieving LTO.
- The LTO of an NPP is operation beyond an established time frame defined by the licence term, the original plant design, relevant standards or national regulations. LTO can be justified by a safety assessment and, depending on the Member State, may take place within a broader regulatory process such as licence renewal or a probabilistic safety assessment (PSA) [4].

In practice, LTO is only possible when an appropriate safety assessment has been performed [4–8], and the results have been found to be favourable. Once safety has been established, the decision to proceed is made based on an economic assessment of the plant's commercial viability throughout the LTO period.

1.2. OBJECTIVE

The objective of this publication is to share the operational experience and lessons learned from techno-economic assessments of LTO on management issues, and on external cost drivers influencing the PLiM of NPPs for LTO in a changing electricity market. The publication shows how project risks are identified and estimated and how cost–benefit analyses are conducted and presented to the stakeholders, in support of an LTO decision.

This publication is intended for the use of the following NPP owners/operators and other stakeholders, in the context of preparing for LTO:

- Utilities or owner/operator;
- Regulatory bodies;
- Architect–engineers/prime contractors;
- Consultants;
- Subcontractors;
- Economic analysts.

PLiM remains the primary responsibility of the NPP owner; the cooperation of vendors, manufacturers, prime contractors and consultants is necessary, however, to generate the required documentation demonstrating the safety and economic and environmental acceptability of planned LTO.

1.3. SCOPE

This publication describes the various approaches to the techno-economic assessment of an LTO project in its specific market environment. It examines the process of defining the technical scope required to extend the operating licence of NPPs and the process of costing the project, inclusive of the management cost, the cost implications of all known external cost drivers and of contingencies. In addition, this publication shows how to conduct an economic study of each electricity market, including the identification of the cost drivers for all competing options, the quantitative probabilistic risk analysis and the development of a cost–benefit business case that compares all options. The information produced is then submitted to the decision makers (e.g. chief nuclear officer, chief executive officer), with all the elements they will need to make a final informed decision, taking into account their goals and those of the other major stakeholders.

Assessments to demonstrate preparedness for safe LTO can be found in other IAEA publications [4, 5].

1.4. STRUCTURE

The publication is structured as follows. Following this introduction, Section 2 describes the three phases of the LTO decision making process. It includes insights into the technical scope and feasibility assessments, recommendations for detailed project evaluation and the elements of project implementation. Section 3 covers the technical, management and external cost drivers for LTO. The technical cost drivers are those stemming from:

— Safety enhancements to meet new regulatory requirements;
— Major replacement/refurbishment of safety and non-safety SSCs;
— Operating and maintenance activities;
— Radioactive waste and spent fuel management;
— Ageing management programme (AMP).

Management cost drivers are those associated with:

— Managing programmes;
— Optimizing outages;
— Financing the licensing process;
— Contractor interface management;
— Promoting a safety and quality culture;
— Training and maintaining expertise.

External cost drivers are incurred from activities related to:

— Security of the energy supply;
— Contributions to the decommissioning fund;
— Social acceptance initiatives;
— Environmental and radiological impact assessments;
— Carbon policies.

Cost drivers may also be related to the electricity market, and to overall risk management as it relates to the implementation of risk mitigation measures.

Section 4 presents the concepts and methodologies in risk management for large projects and, more specifically, for LTO projects. It describes how the main risk factors and associated costs are identified and how the impact of these risks on key performance indicators (KPIs) and financial goals are evaluated. The section also shows how quantitative and probabilistic risk management tools can be integrated into the management framework to identify, understand and manage the various risks associated with an LTO project, and to recognize their impact on technical and economic performance.

Section 5 describes the most common methodologies for conducting an economic analysis. The main objective is to underline the need for a comprehensive socioeconomic cost–benefit analysis (CBA). Such as analysis would include an energy policy, security of supply, competitiveness, profitability, integration of both costs and benefits as reflected by the market, and externalities. The economic performance of the project is evaluated based on costs and revenues attributable to initiating and operating a project for a certain licensed lifetime.

Section 6 outlines the conditions for a successful and efficient implementation phase. It shows how to select contractors and optimize LTO upgrades to manage the testing of the integrated systems and components while maintaining a safe environment. Section 7 contains a summary of recommendations and conclusions.

The appendices provide complementary information. They contain examples related to the main methodologies described in this publication, including a sample cost driver matrix, the template of an economic assessment, a financial analysis model, the contents of a feasibility study, a sample of deterministic and probabilistic methods to optimize safety upgrades and a practical example.

2. DECISION PROCESS FOR LONG TERM OPERATION

2.1. LONG TERM OPERATION: THE STAKES AND THE CONDITIONS FOR SUCCESS

Nuclear power generation contributes significantly to at least two of the main objectives of modern energy policy: the reduction of carbon dioxide emissions and lower generation costs for both the owner/operator and the national economy. Nuclear power generation is a positive factor in the quest for a secure and reliable supply of electricity.

The advantages of nuclear power generation also extend to the LTO period. The profitability of an LTO project increases in proportion to the number of years a plant continues to operate successfully beyond its originally assumed service life. There are, however, three conditions requiring capital expenditure (CAPEX) that must be met in an LTO project:

— Complying with all safety requirements;
— Complying with sociopolitical conditions, such as national energy and environmental policies and objectives and local regulations, as well as working to obtain public understanding and confidence;
— Remaining competitive by maintaining the generation cost of electricity at a lower level than that obtainable from alternative technologies.

In preparing for an LTO project, most NPP owners/operators are well advised to proactively manage their NPP ageing and invest in upgrades to maintain or increase performance, and to comply with safety requirements. Failing to do this may lead to NPPs being in such a degraded condition that the accumulated costs of upgrades, component replacements, refurbishments, modernizations and the like may economically disqualify the NPPs for LTO.

PLiM techniques take into account technical and economic aspects as well as lessons learned from LTO implementation experience worldwide. Most Member States that have gone through the LTO process for their NPPs recommend the following:

— Start improvement programmes early, possibly even ten years before the start of LTO. Invest in safety updates and in improvements to a plant’s operating performance through refurbishment projects, modernization programmes and the replacement of large components.
— Invest in research and development (R&D) since it is an important factor in the successful implementation of upgrades and power uprates. Owners should seek R&D support primarily in the areas of material ageing degradation, technologies to improve ageing control, component replacement methods and processes, and the development of computational models to demonstrate compliance with safety requirements.
— Apply the acquired knowledge and state of the art technologies to achieve the maximum possible operating period beyond the originally assumed service life of the NPP.
— Consider power uprate projects to improve the revenue/cost ratio of NPPs before and during LTO, particularly in the context in which electricity markets are not always favourable to baseload capacity.
— Invest in upgrades suggested in the wake of the Fukushima Daiichi accident aimed at providing the resilience necessary to overcome even a combination of extreme events. Several owners/operators have already voluntarily implemented most post–Fukushima Daiichi improvements resulting from stress tests conducted after the accident. More general recommendations have become mandatory in most jurisdictions. They include upgrades to:
  • Strengthen operator flexibility in responding to an emergency;
  • Increase the robustness of safety related and important systems;
  • Supplement emergency procedures and preparedness in the case of extreme events, such as earthquakes, floods and fire and of their combinations.

These investments are necessary to attain an LTO licence. However, before any decision to proceed is made, costs and benefits must still be carefully weighed against all associated risks.

2.1.1. Key conditions for success

The key conditions for the economic viability of an LTO project are directly linked to overcoming most issues arising from a risk analysis. The following are the main risk groups that should be addressed in a risk analysis of an LTO project: technical and safety concerns, business related variables, and sociopolitical uncertainties.

Technical risks relate to: safety/regulatory and production related upgrades; an environmental impact analysis; project planning; and the implementation phase. The owner/operator relies on internationally accepted designs of LTO upgrades, implements training programmes as necessary, develops sound contractual arrangements and conducts peer reviews under the umbrella of the IAEA or the World Association of Nuclear Operators to verify compliance with regulations and standards.

Once all design changes are approved, the operator should freeze the changes and focus only on implementation in order to avoid non-essential scope and cost creep, which can cause delays. During the LTO project phase, technical risks extend to vendor and subcontractor performance, to the reliability of the supply chain and to construction quality. Once installation of all upgrades is complete, commissioning is successful and the operational phase begins, the owner becomes fully responsible for plant safety and performance, which cannot be maintained without retaining a skilled and experienced workforce. The risk of losing key personnel during the LTO period should be mitigated and should remain a top priority until the end of the NPP's service life.

When dealing with a fleet of NPPs, the owner/operator should strive to implement the highest standardization level possible to facilitate quality management and reduce costs and risks during the contractual phase. This phase includes component manufacturing, fabrication, demolition, reconstruction, field installation and performance testing.

Electricity market constraints, regulations, fuel cost, carbon price policies and their economic and financial impact have to be considered when developing an LTO feasibility study, and the related risks assessed for all possible electricity demand scenarios in order to obtain better estimates of potential investment returns. Demand scenarios are linked to the regional economy, to energy policies and to the potential evolution of the market.

In regulated markets, more predictability is provided to NNP operators. Financial risks are linked to the predictability of the market. A regulated market provides enough transparency to all stakeholders and usually leads to lower financial risk, so that capital costs are lower, overall profitability is higher and stranded assets are avoided.

In deregulated markets, competitiveness is the main driver. In addition, government incentives may be offered to certain sectors to modify the electricity production market mix. These may affect competition and increase the financial risks, especially in jurisdictions where nuclear power generators are highly taxed and renewable generating technologies are subsidized. Under such conditions, NPPs may be forced to shut down for economic reasons, before the end of their service life, even if plants remain safe, mature and stable. As a result of economic headwinds and financial losses, four NPPs in the United States of America (USA) and four NPPs in Sweden will be shut down prematurely over the next two years.

The social and political risks of LTO have increasingly gained prominence over the years. Previously, the public occasionally expressed concerns about prolonging the service life of nuclear facilities that had been operating for several decades. Now, the public demands to be better informed. These social and political risks need to be addressed by the owners/operators, who need to analyse the implications of national policies and local requirements and develop strategies, such as incentive programmes, to maintain public support. Information programmes should present LTO as a safe option, with low CAPEX, since the NPP is already operating in the area, and in line with the long term transition to a low carbon society. In addition, the organization of public debates and the regular publication of opinion polls can produce better awareness of benefits and costs.

Better dissemination of information on plant operation and safety improvement initiatives can help in convincing the public of the lower risk and advantages of nuclear power generation. The most important message is that the facilities are under the strict control of the safety authority and that the nuclear regulator ultimately holds the power to shut down the nuclear facility if it finds evidence that any of the safety requirements are not in compliance. A proactive public information programme can play a large part in lowering the sociopolitical risks and in increasing the probability of public acceptance.

2.1.2. Responsibilities of the stakeholders

Governments are responsible for implementing the overall energy policy in their countries, of legislating equitable market policies, and of establishing a level playing field for competition in the electricity market. As low carbon policies gain ground in many countries, NPPs, with their low carbon footprint, could play a role in the transition to a low carbon society, as coal producers are gradually being replaced with lower carbon alternatives. NPPs may require larger initial costs and impose heavier financing burdens, but they also offer lower fuel costs to offset the higher cost of capital.

As a primary stakeholder, the government is responsible for constituting a competent nuclear regulatory and licensing authority, for protecting the public from nuclear emergencies and, hence, for creating an emergency framework, for its management and for enforcing the right level of nuclear liability.

The nuclear safety authority must be free of conflicts of interest with operators and other nuclear industry constituents. It should be competent and therefore able to acquire the skills and expertise needed to issue regulations and make the right decisions regarding the safe operation of nuclear facilities. Two nuclear safety control instruments have been developed to ensure that operators uphold the licensing basis of their plant throughout the licensing period, including LTO:

— The first is a framework of comprehensive periodic safety reviews (PSRs) [5] conducted, for example, every ten years. Depending on the safety review outcome, the regulator may authorize the licensee to continue operating the plant on the condition that ageing deterioration is well controlled or mitigated and that the latest safety requirements are implemented, or at least planned with an agreed upon deadline. For a licensee with a highly standardized fleet of NPPs, a PSR facilitates efficient implementation of the latest regulatory requirements on the entire reactor series of the same design by taking advantage of the PSR results of the first reactor in the series. Some design changes may vary from unit to unit of the same series, due partly to minor differences in the individual designs or to the different configuration history of units, but the bulk of the changes remains the same across the series.
— The second is the licence renewal application (LRA) process, used primarily in the USA. In the USA, the duration of an operating or combined licence usually coincides with the original design life of the reactor. However, the regulator reserves the right to update its regulations and the licensee is required to comply. Before a nuclear power unit has reached the end of its licence, the licensee may submit an LRA, which triggers a safety review that may lead to a renewed operating licence beyond the term of the previous licence. The LRA is a comprehensive safety verification tool to ensure that licensees comply with ageing and other safety regulations.

The owner/operator is always responsible for plant safety. IAEA Safety Standards Series No. SSR-2/1 (Rev. 1), Safety of Nuclear Power Plants: Design [9], stipulates that:

> “The operating organization shall establish a formal system for ensuring the continuing safety of the plant design throughout the lifetime of the nuclear power plant.
>
> “… The formal system for ensuring the continuing safety of the plant design shall include a formally designated entity responsible for the safety of the plant design within the operating organization’s management system. Tasks that are assigned to external organizations (referred to as responsible designers) for the design of specific parts of the plant shall be taken into account in the arrangements.”

To fulfil this function, the owner/operator must:

— Assume the role of design authority to oversee compliance and configuration control and interface with the regulator;
— Assemble sufficient human resources, and develop and maintain critical skills;
— Ensure that key staff maintain a sound knowledge and understanding of the plant design to operate it safely;
— Gather the necessary financial resources.

Vendors are responsible for the technology and the conceptual design, and architect–engineering firms or the main contractors are responsible for design detail and project delivery to meet the schedule and budget. Lenders and financial institutions provide funds with an adequate risk profile and set the cost of capital as a major parameter in the value chain of the industry.

In terms of engineering support to operations, only large utilities can afford to retain a multidisciplinary design support department throughout the service life of the plant. Smaller utilities can alternatively sign technical support agreements with the original technology vendor/owner and the architect–engineering firm to obtain the necessary design engineering support.

Most NPPs can continue operating beyond their originally assumed service life as long as safety requirements are upheld and kept up to date. Ultimately, the decision to implement LTO is based on economics and on securing sufficient confidence and support from the government, local authorities and the public. Three distinct phases are recognized in the LTO process.

2.2. PHASE I: FEASIBILITY STUDY AND SCOPE

Feasibility assessments are the umbrella activity that first addresses all aspects related to an LTO decision, beginning with an assessment of the condition of the plant and proceeding with the cost of upgrading the SSCs. In order to conduct a feasibility study, the owner/operator has to set up a task force team to manage its development. The scope of a feasibility study normally includes:

— Collecting input data in compliance with the long term national and corporate objectives.
— Assessing the condition of the SSCs that need to be replaced and/or upgraded to meet safety and performance requirements. The assessment should be undertaken within the regulatory framework for safety issues, relying on a dialogue with the regulator in order to reach a common understanding on requirements and to avoid surprises and remedial work.
— Establishing ongoing cooperation with local authorities and the public.
— Exploiting commonalities for multiple units of the same type and identifying solutions that may be shared.
— Conducting an economic study of costs and benefits. The cost of LTO includes the resolution of licensing issues as well as the cost of the social aspects (education, training) and gaining public acceptance. For all input parameters with an uncertainty component, risk analysis techniques have to be applied to identify risks and conduct a quantitative risk evaluation.
— Estimating the difference between the cost of LTO and the expected benefit. In order to complete this step, competing scenarios must be considered to determine the added values of all other electricity generating options.

The feasibility study must show a balance between costs and benefits and at least preliminarily demonstrate the viability of proceeding with LTO. The IAEA has published guidelines on preparing feasibility studies [10] and posted a multimedia training module on its e-learning web site [11].

In regulated electricity markets the decision to proceed with LTO is normally easier because of the built-in transparency and openness of such market models. Transparency allows more solid evaluations and hence more confidence in the expected financial results, including the return on investment.

In deregulated markets, uncertainty about the price of electricity during LTO is high, even though the levelized cost of electricity (LCOE)[2] has been calculated for the various generation technologies. Uncertainties always remain, depending on the merit order of the various technologies and on the incentives that may be offered to specific technologies, both in terms of their monetary value and of their duration. Lack of price predictability and market transparency for the projected LTO period may become a deciding factor for potential investors and without investor support, LTO may have to be postponed or even cancelled. Other channels for investments may be found, but with a history of rejection, the cost of capital may increase significantly.

[2] The LCOE includes the initial investment for plant construction, its operation and maintenance (O&M), and fuel and carbon costs. It should also include provisions for decommissioning.

2.2.1. Considerations related to public acceptance and stakeholder involvement

Understanding the major concerns and motivations of the public is the key to a successful relationship. Owners/operators should endeavour to build trust with the public by clearly sharing information on the benefits and risks of LTO and by thoroughly addressing any concerns.

Listening to and discussing concerns may lead to the strengthening of the legal framework and to the generation of better political decisions, which will benefit the future of a country's energy security. This level of consideration of public input usually goes a long way towards achieving public acceptance of an LTO project.

Formal stakeholder meetings or information sessions aimed at providing facts to all involved have proven effective in the development of a collaborative relationship between the owner/operator and stakeholders. In France, for example, localized information commissions have been set up across the country, near every NPP. They include the operator, local authorities and non-governmental organizations. In other Member States, formal hearings are incorporated into the legal framework. Open debates between the public and the decision makers (owner/operator, government, regulator, industry, etc.) are mandatory. From the owner's perspective, such hearings should be considered as good opportunities for providing correct information and crucial data to all stakeholders, such as:

- A continuing positive environmental impact of the NPP under LTO;
- A continuing reduced carbon footprint and reduced impact on the climate;
- The positive contribution that continuing NPP operation can make to the community;
- The continuity and reliability of the electricity supply;
- The contribution of low electricity prices from LTO to users and to job creation;
- The development of a highly skilled workforce during LTO;
- The increased use of local industrial capabilities in support of continuing NPP operation;
- Any additional social and economic benefits, specific to the community.

Reference [12] contains more information on these topics.

2.2.2. Impact of the Fukushima Daiichi accident on the nuclear industry, with emphasis on long term operation

Following the Fukushima Daiichi accident, many Member States conducted stress tests or extraordinary safety reviews of their NPPs. They made a proactive analysis of the accident, which strengthened nuclear safety, emergency preparedness and radiation protection of the public and of the environment. As a result, recommendations were issued and action plans drawn to incorporate them.

The IAEA Ministerial Conference on Nuclear Safety, held in June 2011, was convened to share the lessons learned from the accident. The outcome of the conference was the compilation of the IAEA Action Plan on Nuclear Safety [13] to collect and disseminate experience, to help Member States reinforce their safety framework, and to form the basis for expert missions capable of constructively reviewing the implementation of their upgrades. The Action Plan eventually generated international recommendations to:

- Evaluate extreme external hazards and their combinations and provide protection where needed;
- Re-evaluate the defence in depth barriers and redundancy in the plants;
- Review the emergency arrangements in light of the lessons learned from the Fukushima Daiichi accident;
- Strengthen the on-site response centre;
- Provide additional equipment to allow more flexibility and options in the restoration of lost safety functions;
- Provide enhanced protection to improve the robustness of the core safety systems;
- Provide mitigation of the risks related to hydrogen releases.

More information on this subject can be found in the IAEA report on the Fukushima Daiichi accident [14]. The implementation of lessons learned from the accident should concern all entities operating NPPs, independent of their location, age or plans for LTO. Most of the actions have already been implemented or are under way in many Member States. Among the most important upgrades arising from the lessons learned from the accident are:

- The installation of hydrogen recombiners;
- The diversification of water and electricity supplies;
- The addition or strengthening of emergency filtered containment venting systems;
- The strengthening of crisis management capabilities and preparedness inside the plant, including the creation of a rapid response force;
- The addition of capacity building activities to improve operator reaction to extreme emergencies;
- The enhancement of communication capabilities with national and worldwide experts and international agencies.

Operators must take into account in their budgets the associated costs and include them in the overall CAPEX of the economic evaluation of LTO. Outside the plant exclusion zone, the government and public authorities have enhanced their public hearing and information systems, which remain a primary government responsibility.

At the end of phase I, the operator will have an overall view of the technical and industrial implications of LTO and be able to rely on a first estimate of the economic aspects. These elements will be sufficient to decide whether to prepare a detailed evaluation and start the licensing process or to terminate the LTO project.

2.3. PHASE II: DETAILED EVALUATION AND LICENSING APPLICATION

In phase 2, the owner/operator undertakes a detailed analysis required for the adequate preparation of a PSR submission for LTO or of an LRA submission to the regulator containing the required documentation. Success will depend on being proactive, consistent and ready with an implementation plan that complies with all regulatory requirements, within the agreed schedule.

In this project phase, cost estimates should be based on firm quotations from suppliers and contractors. NPP owners can obtain lower prices when they are in a position to demonstrate stronger project commitment and good licence renewal prospects. Larger utilities can obtain further discounts because of economies of scale. The detailed economic analysis should provide a more realistic cost per MW·h (LCOE after LTO upgrades). The detailed economic estimate should cover not only CAPEX for the replacement/upgrade of equipment, but also other aspects covered by the economic assessment, such as meeting market demands, the future price of electricity, and external factors, such as social and policy commitments and a carbon tax.

The operator should continue during this phase to provide periodic updates to all stakeholders by being proactive in communications to the public — using announcements, meetings and hearings — and to the shareholders, and by being prepared to efficiently participate in audits from government agencies.

At the end of this phase, the formal LTO application is submitted to the nuclear regulator, followed by an independent regulatory review with a detailed compliance check against the legal and regulatory framework in force. This process varies from country to country. In general, the main steps include a review of:

- The detailed economic approach;
- The power demand forecasts and the rationale supporting industrial and civil development;
- The financial and economic constraints;
- The market context (meeting the energy policy expectations, provisions for the carbon tax, etc.);
- The emergency preparedness capability;
- The compliance with the legal and regulatory framework;
- The communication plan with regard to points of interest, social commitments and performance highlights to stakeholders.

2.4. PHASE III: CONSIDERATIONS REGARDING THE IMPLEMENTATION PHASE

Phase III begins with an agreement in principle between the safety authority and the NPP owner on the framework of the renewed licence or of the authorization to proceed with the LTO period. The safety authority is entitled to demand additional improvements and further reviews before the agreement is approved. However, there may be an agreement in principle that is sometimes characterized as the ‘safety authority green light’.

Once the green light is given, the economic evaluation, including the risk and sensitivity analyses, is finalized, the public and all stakeholders are well informed and their confidence in the regulatory framework is obtained.

The time is now right for financing decisions and the first large disbursements. To that end, the agreement on the regulatory framework for LTO and on government guarantees, if any, must be clear and committed.

For the owner/operator, as for the other investors, clarity and transparency regarding market regulation and safety requirements are of major importance. Otherwise, the investment risks increase considerably and, consequently, the cost of capital increases.

3. COST DRIVERS FOR LONG TERM OPERATION

A cost driver is a factor that can cause changes in the cost of an asset or an activity. Various factors may cause changes in the overall cost of LTO. They are usually grouped in the following categories:

- Technical cost drivers;
- Management cost drivers;
- External cost drivers.

Cost drivers of LTO can also be seen as matrices or determinants that affect the cost of extended operation. In most cases, they are also risk drivers and they are not always the same in all plants. They depend on the reactor type and on the individual plant situation. Cost estimates vary greatly from plant to plant, depending on regulatory requirements, and on assessment of the condition of SSCs, including containment structures. Not all the cost drivers mentioned in this publication should be considered in an LTO project, only those that appreciably affect the specific NPP under consideration.

3.1. TECHNICAL COST DRIVERS

Technical cost drivers affect the cost of safety or performance enhancements. They collectively drive extraordinary projects or programmes, such as plant wide refurbishments, replacements of major SSCs, and modernizations. They are often tied to ageing management initiatives or are triggered by ageing management reviews. They can also be the source of O&M improvements, such as increased capacity of storage of radioactive waste and spent fuel, stretched beyond the immediate needs, but always in line with future LTO projects. These major enhancement programmes may be started long before LTO begins or carried out during an LTO outage. In any case, they are essential to the feasibility of an LTO project.

3.1.1. Safety enhancements to meet the latest licensing requirements

Safety enhancements in most cases are significant cost factors. They are usually implemented in response to unanticipated events, to operational feedback, or to current or highly probable future licensing requirements. They can be categorized along the lines of their original motivation into safety upgrades and safety improvements.

Safety upgrades are those stemming from current and/or anticipated regulatory requirements. They are often implemented when preparing LRAs or PSRs for LTO in countries where the PSR approach is practiced.

Safety improvements usually refer to the addition of new safety related systems or subsystems resulting from updates to PSAs, safety reports and from technical advances (i.e. H_2 recombiner).

3.1.1.1. Safety upgrades

Safety upgrades related to LTO could be driven by changes in regulatory requirements or by current industry practices and operating experience feedback. They are usually implemented ahead of LTO submissions to reduce licensing related risks, restore safety margins, improve operability and benefit from lower maintenance and inspection costs. Examples are:

- — Improvements to the reactor shutdown system(s);
- — SSC upgrades to meet modern seismic and environmental qualification requirements;
- — Replacement of pumps and other equipment to reduce the probability of leaks;
- — Improvements to air handling systems to reduce radioactive emissions;
- — Improvements to the control rod drive mechanism (CRDM);
- — Improvements to water chemistry to reduce the likelihood of corrosion damage;
- — Addition of condition monitoring systems or improvements to existing condition monitoring devices on critical SSCs;
- — Upgrades to the surveillance capsule programme.

3.1.1.2. Safety improvements

Safety improvements are changes or additions to plant systems or system configurations that were not considered at the time of initial commissioning or original licensing. These improvements may have been driven by subsequent revisions to the safety analysis and to the final safety analysis report (FSAR), by an updated risk analysis or by new regulatory requirements. Examples are:

- — Changes that facilitate compliance of all safety related systems with the single failure criterion, if it was not built into the original design, to align the plant with common industry practice;
- — Modifications of the plant layout to improve the segregation of safety related electrical equipment and mechanical components;
- — Improvements in component redundancy, system diversity and system integrity protection, such as the provision of alternative power sources;
- — The addition of emergency control facilities, such as a new emergency or secondary control room at the plant site, or the addition to an existing emergency control room of monitoring systems of peripheral areas, such as the spent fuel pool;
- — The addition or extension of the off-site technical support centre with advanced communication facilities, remote display capabilities of critical safety and control parameters;
- — Improvements in redundancy, diversity and maintainability of the safe shutdown systems and of electrical power sources;
- — Segregation of redundant systems, to protect from common mode failures in fires, floods or other adverse safety related risks from internal and external events;
- — The addition of passive hydrogen recombiners to reduce the risk of hydrogen explosions in severe accident emergencies;
- — Improvements in the availability or reliability of the accident and post-accident monitoring instrumentation in the main control room, in the emergency control centre on-site and in the technical support centre off-site.

Some safety improvements may originate from studies and lessons learned from the Fukushima Daiichi accident. These may be regarded as a separate cost factor, as they may not have been included in the feasibility and scoping activities (phase I) of the LTO project.

Plant refurbishments and replacements of major safety related SSCs may become necessary to mitigate ageing or obsolescence and chronic shortages of critical spare parts. Replaceable systems and components may include steam generators, pressurizers, reactor vessel heads, CRDMs, reactor internals, primary pump internals, shutdown systems, instrumentation and control (I&C) systems, electrical systems, cables, emergency diesel generators, large diameter primary circuit pipes and fuel channels for CANDU reactors. Any replacement or refurbishment scope should be customized to the specific plant design, not vice versa. The necessity and feasibility of each component replacement depends on the reactor type, on the specific detail design and on the SSC condition assessments. Table 1 shows examples of major components and systems that have typically been replaced. Some of these replacements may have been motivated by future LTO plans.

TABLE 1. LIST OF USUALLY REPLACED SYSTEMS AND COMPONENTS

Structures, systems and components	Type of reactor			
	PWR	BWR	WWER	PHWR
Steam generator	✓		✓	✓
Pressurizer	✓			
Pressure vessel head	✓			
Control rod drive mechanisms			✓	
Reactor internals		✓		
Fuel channels				✓
Instrumentation and control system	✓	✓	✓	✓
Electrical systems			✓	
Cables	✓		✓	
Large diameter primary circuit pipes	✓			

The component replacement scope is dictated by the ageing management and PLiM programmes and confirmed by targeted in-service inspections, condition monitoring, testing and maintenance reports. In general, owners/operators implement more replacements/refurbishments than strictly necessary during the NPP design life in anticipation of an LTO submission. NPPs that have been better maintained during their design life require fewer replacements, hence less capital investment for LTO.

The capital cost of large equipment replacements or extensive plant refurbishments can be broken down into cost items by discipline:

— Design and engineering costs;
— Documentation costs (e.g. seismic or environmental qualification costs);
— Manufacturing or purchasing costs;
— Transportation costs;
— Construction and installation costs;
— Radioactive and conventional waste management costs;
— Other costs (e.g. training).

Indirect costs may be incurred during heavy equipment replacements or extensive refurbishments. For example, if the refurbishment causes an outage extension, the extension itself is considered a major indirect cost driver. Good preparation, proper timing and proper planning can limit LTO outage extensions. In general, more scope affects the cost of the LTO process. Section 6 provides more information on the implementation of plant improvements.

3.1.2. Security enhancements

Older NPPs may not have been designed and constructed to the same physical security standards that apply to new plants. The LTO review should examine the extent to which provisions for physical security can be augmented. This review should confirm that there are no impediments to the implementation of security measures against new anticipated physical threats and risks. New requirements stemming from new threats generally relate to the availability of backup security command centres, of uninterruptible power supplies to threat detection systems, of enhanced video capability, of new adequate protection barriers from airborne and water-borne physical threats.

Some Member States continually monitor the adequacy of physical plant security and require immediate improvements to ensure continuing adequacy. In such cases, there is no need for a specific reconsideration of physical plant security to support LTO.

3.1.3. Operation and maintenance cost drivers

O&M costs during LTO are no different from those of the first licence period. They include all expenditures necessary for plant operation except for fuel cost and, for CANDU type reactors, heavy water make-up. Generally, O&M costs are estimated based on the average capacity factor of the plant, under normal operating conditions. Examples of O&M cost items are:

— Labour (gross wages, social security contributions, taxes, etc.);
— Consumables and material equipment;
— Contractor services;
— Nuclear insurance;
— Licensing and regulatory fees.

The requirements for spare parts and consumable inventories during LTO should be assessed, as well as the cost of their procurement, storage, upkeep and management. The operating experience of NPPs indicates that it is prudent to maintain an optimal inventory of operating spares to ensure that LTO will yield high capacity factors with minimum interruptions. While the supply of most common components is readily available from a number of suppliers, plans should be made to secure the supply of specific sole source components, of obsolete components and of long lead items.

System health and condition monitoring of sensitive parameters is necessary during LTO so that the operator is immediately notified when the operating parameters of major safety components approach their limits. The cost of developing, installing and operating advanced condition monitoring systems (e.g. enhanced radiation monitoring systems) should be considered part of the LTO costs. Figure 1 shows some examples of monitoring systems that have been considered for LTO.

O&M costs identified or modified because of other programmes should also be included in the overall O&M cost. Any unforeseen or unplanned new regulatory or management requirement may also affect O&M costs and staffing plans. Contingency estimates and provisions for them should be part of the economic assessment of the LTO process/budget.

3.1.4. Power uprate projects

The cost of changes and improvements, such as power uprates, should be evaluated in the context of the overall cost of electricity generation, and recognized as input into the economic evaluation of the LTO option. Power uprate projects could bring considerable economic benefits to LTO because of the higher revenues obtainable from the operation of the uprated plants. Power uprates engender costs such as:

— Licensing costs.
— Additional documentation and engineering costs (e.g. thermal–hydraulic calculations, safety analysis, structural analyses, etc.).
— Fuel modifications (use of high burnup fuel or mixed oxide fuel). LTO may include changes and radical improvements to the fuel cycle, such as shortening of the refuelling outage or improvements to the fuel element configuration using higher enrichment levels.
— Replacement of secondary side components for more efficient ones (turbine parts, generators, moisture separator reheaters, feedwater heaters).

In some countries, power uprate is considered a separate business case and therefore its costs and benefits are not included in LTO economic models. Reference [16] provides more information.

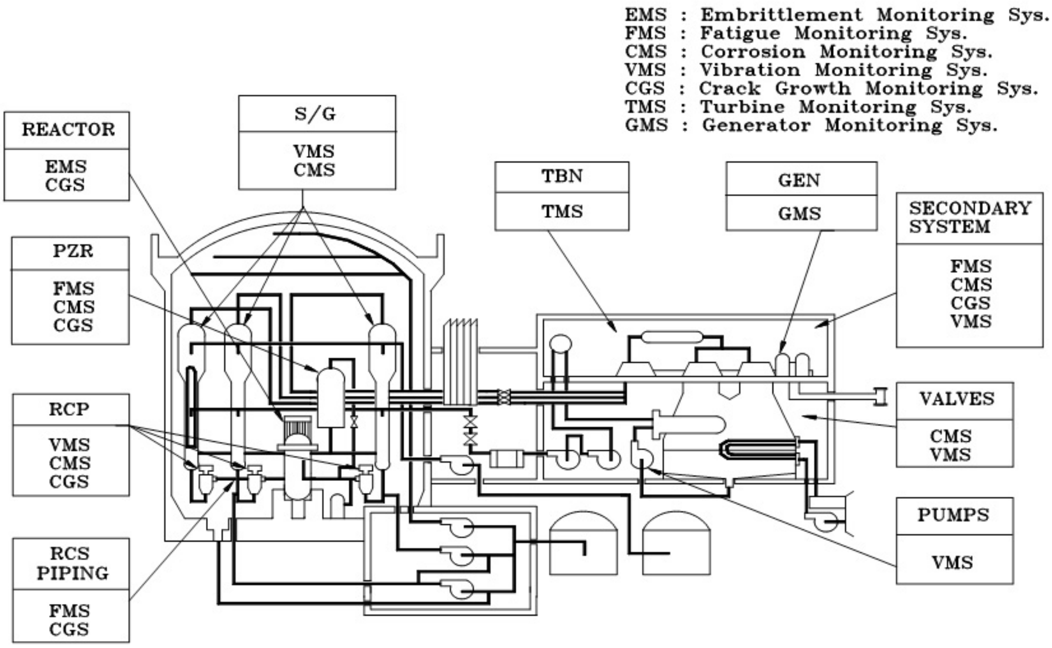


FIG. 1. System health monitoring system in NPPs [15]. GEN — generator; PZR — pressurizer; RCP — reactor coolant pump; RCS — reactor coolant system; S/G — steam generator; TBN — turbine.

3.1.5. Radioactive waste and spent fuel management

Spent fuel is stored on-site at most NPPs. On-site storage may be included in the initial design or added later because of a lack of off-site alternatives. A major cost factor of LTO may be the need for further enhancement of the storage capability to accommodate the extra radioactive inventory. The spent fuel may have to be compacted to accommodate the incremental volume and additional storage capacity may be needed.

Beyond the need for extra fuel storage, an LTO project will always result in additional radioactive waste because the dismantling of structural components to be replaced will produce irradiated waste, which will require radioactive storage for an extended period. Therefore, the NPP operator may be required to evaluate the many technical and economic issues related to the substantial increase of radioactive waste from LTO project implementation. The existing storage facility may have to be expanded. The extra storage capacity required for the management and disposal of liquid and solid radioactive waste from LTO, and the need to purchase new dry storage casks to cover the LTO period, should be considered in the LTO cost matrix.

The economic burden will further increase if the existing on-site space available for radioactive storage capacity expansion is limited. This may mean that the additional radioactive waste and spent fuel may have to be transported to other storage sites, incurring incremental costs to cover the transfer of radioactive material, the enlargement of the receiving facility, the extra storage canisters required, and related storage fees.

3.1.6. Ageing management programme

Ageing management encompasses a broad range of activities, including maintenance, surveillance, equipment qualification, in-service inspection, water chemistry control and other plant programmes. An AMP should be established before embarking on an LTO project [6]. In some countries, an AMP is applied to long life passive components only in safety systems for the LTO period for the licence renewal submission, as per regulatory requirements. In other countries, it is a separate item. The costs of ageing assessment and mitigation should be included in the economic assessment, namely:

— The AMP itself;
— The resulting changes in the AMP;
— The required time limited ageing analyses (TLAAs).

Ageing management addresses physical ageing effects, such as degradation of SSCs to a point where their safety and functionality could be impaired. Degradation mechanisms may lead to cracking, loss of material (e.g. corrosion, wear) and changes in material properties. TLAAs are required for safety related structures and components to be revalidated for the effects of degradation mechanisms (e.g. fatigue, radiation induced creep) and of degradation associated with harsh environmental conditions. In some cases, technological obsolescence should be considered while assessing preparedness for LTO [4].

Technological obsolescence is an important factor in sectors where rapid technological changes occur, especially in the instrumentation, control and computer fields. Rapid technological change could bring to the forefront obsolescence, particularly when it involves safety related SSCs. The replacement of obsolete equipment or the procurement of sufficient spare parts is essential to ensure the survival of the affected SSC for the entire LTO period.

In some countries, regulators set the performance criteria for safety equipment and the operator is required to update equipment whose performance criteria cannot be met because of obsolescence. Other than being a regulatory concern, obsolescence may be a major cost driver. Examples of how to set the hierarchy and classification of ageing management issues are given in Ref. [3]. Other IAEA publications pertaining to ageing management issues can be found on the IAEA web site [17].

3.2. MANAGEMENT OF COST DRIVERS

Management of NPP operation and its programmes, including LTO, always has a great impact on plant safety and performance. Operators are normally required to review and assess their internal management programmes. This is usually achieved through self-assessments or through regulatory oversight, which may lead to improvements of the management programmes and processes. Examples of such programmes and processes may include:

— Configuration management;
— Self-assessment;
— Corrective action;
— Design basis documentation;
— Safety culture work environment;
— Work management;
— Computerized work management information system;
— Quality assurance and quality management;
— Operator training and management oversight.

Beyond managing programmes and processes, the management team is also responsible for managing cost drivers in LTO, of which the main ones are LTO outage optimization, control over the licensing process and retaining the necessary level of in-house expertise. These cost driver control activities are described in the following subsections.

3.2.1. Long term outage management optimization

Optimization of outage strategies and outage management may differ from plant to plant due to a number of factors, such as:

— National regulations and legislation;
— Owner/operator strategies;
— Specific NPP design and technology;
— Plant ageing or PLiM solutions;
— Health conditions of the critical path systems and components.

The outage optimization path will vary, depending on the:

— Plant technology (PWR, BWR, CANDU, WWER, RBMK, etc.);
— Plant configuration, particularly items such as the redundancy level of the safety related systems (two, three or four trains), turbine power train (one train versus two), the number of reactor units in the NPP and the level of shared components among the units;
— Fuel cycle (12, 18 and 24 month fuel replacement) or on-line refuelling;
— Main component overhaul requirements (annual, every other year, every third year, etc.);
— Pressure vessel inspection programmes mandated by local pressure vessel and pressure retaining component regulations;
— Type and extent of the pressurized system tests based on the pressure vessels and pressure retaining component regulations;
— The price of electricity and the mechanisms influencing it.

Typically, there are four general types of outage categories:

— Refuelling outages, in which only urgent repairs, if any, are done. Essentially, only annual maintenance is perfomed for these outages.
— Short outages, held every second year, in which the critical path is driven by mandatory inspections, tests and maintenance of systems/components with a two year maintenance cycle.
— Long outages, in which the critical path is based on the pressure vessel inspection (typically required every five years).
— Extra long outages, in which the critical path is driven by a pressure vessel inspection, followed by a pressure test (typically required every ten years).

The best way to achieve outage management optimization is to minimize their critical path. The shortest duration of each of these standard outage types equals the shortest critical path achievable for each of the major maintenance and inspection activities. Once these four outage categories have been optimized, any other activity should be accommodated within the outage critical path with parallel interventions.

Whenever ageing related maintenance or other modifications are contemplated, all options should be explored, taking into consideration economic, risk and performance factors.

The economics of large investment programmes should be based on net present value (NPV) calculations over the remaining plant lifetime, including LTO, and on sensitivity evaluations of cost parameters. Among the cost drivers that may influence the results of LTO profitability evaluations are:

— Material movement in large projects such as I&C modernization programmes and turbine island component replacements (steam turbines, generators, moisture separator reheaters, preheaters etc.). One of the least known cost drivers in large refurbishment projects is the lack of cranes of the required type and capacity and their operability within the confines of an existing facility. Cranes used during initial plant construction will not be available for much later reinstallations of SSCs (e.g. in support of large modernization projects, uprates, LTO refurbishment programmes). Even if cranes were made available, their use should be carefully planned in order to avoid outage extensions due to crane overbooking, physical and schedule interferences and activity replanning.
— Production losses in LTO due to accelerated SSC ageing degradation. This happens when refurbishment programmes are postponed or simply cancelled on budgetary considerations without conducting sufficient ageing degradation studies.
— Unexpected degradation mechanisms, discovered during testing and inspections. In order to minimize losses of this nature, the installation of on-line condition monitoring systems, at least on critical components, can provide early warning of degradation and allow the adoption of mitigation measures, resulting in less onerous life assessments in LTO projects.
— In heavy component replacement projects, plant layouts may not be predisposed or amenable to component replacements (e.g. obstacles along the steam generator replacement route).
— Electricity price trends, where market postures are difficult to predict.
— Total investment cost, interest rate predictions and the weighted average cost of capital (WACC).

3.2.2. Licensing process

Cost drivers associated with the licensing process are influenced by the regulatory regime. They are generally incurred for:

- Studies needed to prepare the licensing documents, such as integrated plant assessments of ageing effects, environmental impact assessments (EIAs), and TLAAs.
- Regulatory fees for the application review.
- Responses to regulatory questions, audits or inspections.
- Implementing regulatory commitments.
- Legal challenges, public hearings and interventions. Public interventions attempting to delay or stop the licensing process for LTO may have a large impact. Although interventions are rare, when they occur, the regulatory review process may take significantly longer (e.g. 60 months or more versus 24 months with no intervention) and the cost to address legal challenges may be as high as hundreds of millions of US dollars.

3.2.3. Maintaining expertise

The cost of maintaining the expertise required for LTO should be included in any economic evaluation. If the plant organization already has a good human resource succession planning process and an adequate level of experienced staff to ensure mentoring and knowledge transfer to junior staff members, then this cost will not be added to the LTO assessment.

However, as is often the situation, if the plant organization lacks adequate staffing for effective mentoring and knowledge transfer, additional measures must be taken to ensure the expertise needed for LTO remains available or is reacquired.

Specific studies of the situation in individual plants may be required to determine the magnitude of this cost impact on LTO. The cost of maintaining expertise may include adding new junior and experienced staff to the plant organization to ensure that knowledge transfer occurs and expertise is maintained. In some cases, it may even be necessary to build new training facilities or to extend existing ones, which means added costs.

3.3. EXTERNAL COST DRIVERS

External costs are incurred when an external party takes an action or conducts an activity that imposes costs on the project. External cost drivers [18, 19] are conditions external to the project that lead to the generation of costs such as:

- Security of energy supply;
- Ensuring social acceptance;
- EIAs;
- Carbon policy;
- Electricity market;
- Risk assessment and mitigation measures;
- Decommissioning.

3.3.1. Security of energy supply

The International Energy Agency (IEA) defines energy security as "the uninterrupted availability of energy sources at an affordable price".[3] Lack of energy security can mean either a physical unavailability of energy, or an energy supply at prices that are not competitive or are overly volatile. Depending on the period considered, energy security may impose different demands, and hence different types of external costs:

[3] http://www.iea.org/topics/energysecurity/

— Long term energy security, which may require investments to supply enough capacity to support the economic development of the region, while respecting the requirements for a sustainable environment. This may occur at a time that may not be economically profitable.
— Short term energy security, which requires the ability of the existing energy system to react promptly to sudden changes in energy demand. Extreme price spikes may cause economic damage. Disruptions can affect other fuel sources, the infrastructure and the end user economic sectors.

Nuclear power generation is a technology that could contribute to increasing the reliability of the energy system, in terms of both service and price [20]. An analysis of the contribution of nuclear power to a country's energy security is needed when seeking to secure the supply of energy. However, the increasing complexity of energy systems also requires a systematic and rigorous understanding of the whole range of options and of their vulnerabilities.

3.3.2. Social acceptance

This is an external cost driver for the owner/operator, but it is a crucial one. Public opinion can influence governments and their policies, including energy policies, LTO decisions and changes to market structures. Project stakeholders can engage the public through a number of initiatives in which they explain the conditions needed to operate an NPP in an accepted manner. The process must be initiated as early as possible during the feasibility assessment phase of the LTO plan, and must be carefully planned and deployed for a successful outcome. It should include a series of steps intended to create the conditions of acceptance among the different parties. The first of these is the identification of the key stakeholders, including the public and local authorities, and the acknowledgement of their main concerns. If no other national/industry specific procedures are in place, a project contextual assessment is needed consisting of a detailed characterization of the NPP conditions. This characterization phase [21] will aim at:

— Characterizing the context of the LTO of a specific NPP;
— Identifying the positioning of each stakeholder (stakeholder mapping);
— Analysing and ranking the issues and concerns of each stakeholder that are likely to influence their position with regard to LTO.

This information is then used to define a stakeholder engagement strategy that creates the right conditions for an exchange of opinions and eventually a convergence among the parties, leading to an acceptable distribution of costs and benefits among all the project stakeholders. A staged approach has been proved to work best. Dedicated stakeholder meetings are organized with the objective of reaching a consensus on the LTO options. During these meetings, the LTO project and any other option should be discussed and evaluated, using a set of commonly accepted criteria.

In addition, public outreach techniques, communication and educational programmes are needed if it is felt that they could contribute to reaching a positive outcome.

If the NPP owner/operator lacks the competence in-house, professionals in the social sciences and communication can be hired to plan activities and carry out public events. The cost of the social acceptance activities should be estimated, including:

— Activity planning;
— Hiring of professionals;
— Personnel involved in the activity;
— Communication materials;
— Communication events;
— Modifications to the original LTO plan to accommodate public issues/concerns;
— Benefit offered to the local community (e.g. sport centres, social centres).

3.3.3. Environmental impact assessment and carbon policies

If required by national regulations, an EIA of an LTO project should be prepared and submitted for regulatory review. The report should address plant specific data and show compliance with environmental regulations. These rules are usually distinct from nuclear related regulations. Where relevant, the environmental review process should be integrated with the nuclear licensing process to avoid jurisdictional overlap.

The overall cost of the EIA and of its recommendations should be estimated, including any modifications required both internally and externally to the plant. These may include modifications to the plant layout, to plant procedures or to personnel training. They should also include any other external cost required to align the plant with environmental regulations.

The planning, management and preparation of the EIA are key factors in terms of cost control, especially since the entire process is cumbersome and includes activities such as public hearings and government or public institution assessments. These can take a long time, in some cases up to ten years.

Carbon policy is a country specific policy choice that influences decisions regarding the energy options being considered. In general, a national carbon policy and international agreements on environmental issues that may have been signed by the country in this regard should be taken into consideration in the LTO feasibility and cost analysis.

The United Nations Framework Convention on Climate Change (UNFCCC) was launched in 1992 with the objective of generating strategies to limit global average temperature increases and reduce the effects of global climate change. In 1997, the Kyoto Protocol was adopted to legally limit greenhouse gas (GHG) emissions in developed countries. The commitment period runs until 2020. In 2011, during the Durban conference[4], governments agreed on the need for a new mechanism, to be implemented after 2020, to stabilize GHG concentrations in the atmosphere to a level that will slow down climate change.

Currently, the mechanisms under implementation, such as the Joint Implementation projects, clean development mechanism (CDM[5]) and carbon emission market[6] do not include nuclear power as a valid option to reduce emissions. This situation may change; it is expected that nuclear power will play a role in the development of new agreements or through the amendment of existing ones [22].

3.3.4. Electricity market

Entities generating electricity in a region or country must continually balance supply and demand. Sufficient plant capacities need to be installed well in advance and cover peak demand well into the future. This means that power plants may have to be built even at a time when electricity demand is low and electricity producers face serious cost uncertainty.

In the last century, electricity supply was modelled according to two variants:

— A vertically integrated public monopoly;
— Local monopolies for the retailing phase and a national monopoly for the production–transportation phase, integrated by a long term contractual relationship.

The recent liberalization of the electricity market in many countries has imposed a new organizational style. On the one hand, the main distribution and transportation networks are still considered strategic infrastructures and remain natural monopolies, controlled by a regulating body that has to ensure access to producers and users alike. On the other hand, the production side and the local selling of electricity (wholesale and retail) have become free activities governed by competition.

In parallel with the liberalization of electricity markets, energy and climate change policies have been introduced. These include carbon emission reduction systems such as carbon exchange or carbon tax systems,

[4] United Nations Climate Change Conference, Durban, South Africa, November 2011.

[5] In the CDM protocol, countries are allowed to purchase GHG reduction units from countries with low GHG industries in order to meet their emission targets.

[6] Carbon emission trading is a new market-based method created under the sponsorship of the UNFCCC to reduce GHGs. It uses a ‘cap and trade’ system whereby the government sets a cap on carbon dioxide equivalent emissions. Companies with emissions below the cap can trade their credits with third parties.

green certificate systems, European-style emission trading systems and feed-in tariffs. In addition, direct incentives for renewable sources have been offered to favour power generation alternatives that do not produce any carbon emissions.

This kind of market environment heavily affects investment decisions because investors in traditional large baseload generators now have to face new and higher risk factors. Where risk is high, investors tend to favour flexible options, with short lead times and low capital requirements.

Major factors that increase investor risks are large variations in demand, inefficiencies of price signals or mixed signals from the market, uncertainties in the licensing processes, the non-storability or the high cost of storability of electric power and the propensity of policy makers to change market rules or experiment with new rules and change market institutions. Other market-based factors influencing investments include:

- The need to balance supply and demand at every point of the network, which introduces production inefficiencies;
- The inability to control power flows to most retail consumers;
- The limited use of real time pricing by retail consumers;
- The need to rely on non-price mechanisms (controlled rolling blackouts that shed load to match demand with available capacity), orderly rationing to equalize imbalances.

Competitive wholesale markets of electricity and other forms of energy have often failed to provide adequate net revenues to foster investments in generation capacity to meet reliability criteria with large baseload generators. Consequently, policy makers in many countries are starting to debate whether competitive wholesale electricity markets require incentives to stimulate adequate investment in traditional and reliable generation capacity or in the life extension of existing plants. The crucial question they face is whether electricity producers in liberalized markets will continue to prefer traditional large capacity units to draw benefits from the economy of scale and low production costs, or if price uncertainty and competitiveness will force them to favour smaller units to reduce risks.

In a liberalized market environment, the uncertainties of future returns and of production costs are among the most critical factors affecting the willingness to invest. Under such conditions, investors in power generation must take into account a much larger and diverse set of business risks, both old and new:

- Licensing risks;
- Regulatory controls;
- Political risks affecting revenues, costs, and financing conditions;
- Price and volume risks stemming from market uncertainties;
- Fuel price and supply risks;
- Risks arising from investment financing;
- Factors that may influence the electricity demand and affect the supply of capital and labour;
- Security of supply;
- Escalation of decommissioning and of radioactive waste disposal costs.

All of these contribute to increasing the overall financial risk perceived by investors and consequently jeopardize their expected returns.

The redistribution of risks among the different stakeholders is likely to make nuclear power generation unattractive, even when its levelized costs are similar to those of competing technologies. In liberalized markets, the choice of technology is fundamentally left to market forces.

3.3.5. Political influences

Political influence can be a very important factor affecting the future costs of NPP investments and operation.

In March 2015, the European Union’s Supreme Court ruled that a tax on users of nuclear fuel or a tax on spent fuel were in accordance with the EU Constitution. This legalized the introduction of special taxes or fees for NPPs (e.g. the nuclear fuel tax imposed in Germany), increases to existing fees, changes in nuclear insurance policy conditions, new safety requirements and the like.

Political influence has also affected the costs of LTO, with tax increases and fee hikes imposed on decommissioning and/or on the disposal of radioactive waste.

In an economic assessment of LTO, all such factors, whether factual or even only possible, are considered ‘real’ external cost drivers.

Political decisions are in most cases the result of public opinion. Therefore, maintaining good public relations for a nuclear power operator is always of primary importance.

3.3.6. Decommissioning

The technical and costing aspects of decommissioning NPPs at the end of their service life have been studied in detail, and a number of reactors have been successfully decommissioned. For the majority of nuclear plant operators, financing provisions for the decommissioning of NPPs are included in the price of electricity. Thus, at the end of the originally assumed design life, the accumulated provisions for decommissioning should be sufficient to pay for the plant shutdown, for its decommissioning, and for the return of the plant site to an ecologically acceptable state if not to ‘green field’ conditions, depending on the regulatory requirements in force.

A typical decommissioning cost break-down will include the following cost items:

— Low level waste handling and disposal costs;
— Spent fuel and high level waste handling and disposal costs (the costs for additional dry storage casks and for greater dry storage capacity, as well as the costs associated with permanent storage in deep geological repositories);
— Collective labour dose equivalent received.

The LCOE includes the initial investment for the plant construction, its O&M and fuel and carbon costs. It should also include provisions for decommissioning. In the cost structure of nuclear electricity generation at a 5% real discount rate, decommissioning is about 0.3% [23].

In considering LTO options, the financial implications of a decommissioning fund must be carefully evaluated. A sum of money disbursed by electricity users throughout the service life of the NPP, as a portion of the price per kW·h, is earmarked for plant decommissioning from the beginning of operation. When the plant service life is extended as in LTO, the decommissioning process that was originally envisaged will be delayed for the duration of the extended period. This causes interest to accrue on the decommissioning fund. The LTO economic evaluation should include the economic and financial benefits of delaying the decommissioning process. For plants with decommissioning funds collected during operation, the LTO results in:

— Interest accumulated during the LTO period on the frozen decommissioning fund.
— Lower electricity fees collected per MW·h. Decommissioning is paid off. The electricity user does not pay for the decommissioning portion of the price structure and the price of electricity becomes more competitive.
— Marginally higher cost to the plant owner/operator, due to larger waste volume and more spent fuel generated during LTO.

The overall net impact on LCOE is generally positive (i.e. lower LCOE) due to lower electricity fees charged to customers and to interest accumulated by the decommissioning fund that grows during LTO.

3.4. COST DRIVER MATRIX

A cost driver matrix is a tool designed to provide a systematic and comprehensive summary of all aspects of cost evaluation for LTO. Alternatively, it is also possible to develop a specific ‘live’ database that allows selective data extraction, searches, calculations and other work with cost drivers. An example of a cost matrix is presented in Appendix I. An example of a database developed in the Czech Republic is presented in Appendix II.

Utilities conducting feasibility studies may have to prepare two or more sets of data (i.e. cost driver matrices) for 10 or 20 or more years of operation beyond the originally assumed design life. The financing for 20 years of operation beyond the plant design life is not going to be double the ten year figure because ageing mitigation and its cost are not linear functions of time. Cost estimate comparisons between various lengths of LTO are discussed in Appendix II.

An LTO project undergoes several development phases, such as the feasibility study, R&D, engineering, analysis, licensing, documentation and contract awarding, material procurement, execution, commissioning, acceptance and turnover. A cost driver matrix should cover all activities. However, the costs listed in the cost driver matrix may not be required all at once. Yearly disbursements usually follow the activity timeline. The LTO feasibility study, the SSC health assessment process and other relevant preparatory work start well before the end of the originally assumed design life. Generally, disbursements of funds for LTO projects start with the feasibility study and continue with each activity or group of activities throughout the LTO preparation period, including the licensing related effort. These disbursements continue until plant restart.

4. RISK MANAGEMENT

4.1. OVERVIEW OF RISK MANAGEMENT

It is impossible to eliminate all risks in human enterprises. Risks can only be mitigated or exchanged. Three major aspects characterize risk analysis in industrial projects:

- The type of adverse event;
- The probability of the adverse event;
- The severity of the consequences incurred from this adverse event.

Probability and severity are two statistically indefinite variables that require a large amount of data for a quantitative risk assessment. The popular definition of risk as the product of the probability of an event times its consequence is insufficient in the risk management of large projects. Even in single case scenarios, equating risk with a single number, namely ‘probability × consequence’, is ambiguous, since it would lead to the conclusion, for example, that a low probability–high damage scenario equals a high probability–low damage one. It is more appropriate to think of risk as a curve and even more comprehensively, as a family of curves, in multiple case scenarios, and even as a family of surfaces for different categories of damages, such as cosmetic damage versus structural damage or loss of life. In addition, any list of scenarios in risk analysis can be criticized as being incomplete. This is because the number of scenarios is infinite. It is therefore imperative to make allowances for unknown combinations of events and contingencies and assign them a probability distribution.

Risk in relation to investments in energy projects, including LTO projects, is conservatively described by the negative impact which uncertain future events may have on the financial burden of the project. It is important to note that risk is not the same as uncertainty. Uncertainty about the evolution of the financial burden of a project can be both positive and negative. Risk, on the other hand, relates exclusively to events that lower the expected financial value. Uncertainty about future events that increase the expected value is referred to as the ‘upward potential’. Although both risk and upward potential are related to future events, risk usually plays a more dominant role in investment decisions, since investors are in most cases highly risk averse.

The level of detail involved in assessing project risks depends on the importance, the size and the complexity of the project. The methods and the models used to assess risk are as adequate as the results are sufficiently detailed to allow an informed decision.

Risks are not all equally important. To decide which need to be formally analysed will depend on whether the uncertain variable has a significant effect on the decision to be made. The data collected should be proven. Subjective data can only be used in interim estimates or in defining trends to guide first level planning or exploratory investments. They should also be relevant to the LTO project and to the alternatives at hand. The more relevant and proven the data, the lower the uncertainty of the outcome. The data should also be relevant to project objectives, such as the NPP improvement plans and their expected effects on the project; they should be compatible with the creation of opportunities and with possible mitigation measures. The collected data should also include enough information to define the probable future degraded condition of the plant, if mitigation measures were not applied.

There are specific ways to deal with different kinds of uncertainty. Some uncertainties may exist because of a lack of information or of skill. These can be reduced by obtaining knowledge through education, training or by seeking expert guidance on the job. Some uncertainties may also be removed or reduced through more research and/or more development time. Some knowledge gaps may include events that appear random and hence unpredictable; some may be hidden or unknown. Others may just be beyond the current knowledge or state of the art. They should be acknowledged and treated as contingencies. Risks in industrial projects can be grouped as follows.

Project risks

These risks relate to the project development phase, which in the case of an LTO project refers to the development and implementation phases, including:

- Project planning and scheduling;
- Conceptual design of safety, reliability and performance improvements;
- Major equipment replacements, power uprates (if any) and modernization projects;
- Licensing submissions;
- Detail engineering;
- Bid information specification;
- Equipment procurement (manufacturing, transportation);
- Planned and unplanned detail installation gap engineering, field changes;
- Demolition of old and installation of new sections;
- Risks related to protecting the environment from the effects of radiation;
- Waste disposal;
- Security enhancements;
- Risks related to the ability of the refurbished plant to operate at the required performance levels;
- Project management and integration issues;
- Issues related to scope creep;
- Cash crunches;
- Hardware and software issues;
- Human resource issues, such as attrition, training;
- Supply chain issues, possibly leading to cost overruns;
- Schedule delays caused by cascading effects.

Technical and safety risks

NPPs have a number of independent backup systems designed to intervene if normal operation of the plant is disrupted:

- The accident at Three Mile Island proved that serious events could indeed occur and produce enormous loss of property, even without causing off-site damage.
- The Chernobyl accident also caused loss of life, in addition to large scale property damage, both on-site and off-site. Increasing concerns about reliability and safety have led to ever more built-in safety systems and precautionary redundancies.
- Risks involving nuclear safety are normally split among the government, the insurance industry, the owner/operator and other major stakeholders, as spelled out in national nuclear legislation and in formal agreements among the parties.

Business and market risks

The fate of an LTO project is strongly affected by the energy market structure. Market risks relate broadly to unexpected adverse changes in the national economy. The data projections and assumptions initially made in an LTO economic analysis, such as the impact of inflation or decommissioning costs, may become invalid. When the evolution of the GDP and the future direction of the economy are uncertain, the electricity demand to which they are tied also becomes uncertain. Uncertain electricity demand produces volatility in electricity prices, which can heavily skew predictions. Market risks are normally linked to highly fluctuating fuel costs, carbon dioxide policies and electricity prices. Electricity markets are characterized by:

- Large variations in demand over the course of a year;
- The need to physically balance the demand and supply at every point of the network;
- The non-storability of electrical power;
- The inability to control power flows to most individual consumers;
- The limited use of real time pricing by retail consumers;
- The necessity of resorting to non-price mechanisms (even blackouts) to deal with imbalances, since markets cannot react quickly enough to avoid them.

At the opposite end of the spectrum, tight price regulation can also be detrimental. Policy intervention may prevent electricity prices from rising high enough to support new investments. The risks involved in regulating the price could become even more of a concern, when coupled with a climate change policy. These types of regulatory interventions may significantly affect investment risks and lead to inadequate generation capacity.

Political risks

Governmental commitment to nuclear power development is a prerequisite for nuclear construction because of its safety implications, but that commitment is not a guarantee that taxation, laws and regulations governing electricity markets may not change and harm investments in nuclear power generation. Policy related risk factors are linked to the various forms that policy intervention may take, for example, a policy whose objective is minimizing environmental effects. Environmental policies may require additional investments to meet tighter standards, or may even force some capacity reduction. Other political risks that may directly affect NPP operation are changes to the national radioactive waste and spent fuel management and decommissioning policy, changes to the tax regime, and the like. In the past, drastic retroactive regulations, phase-out decisions and so on have caused disputes about licensing, local opposition to cooling water sources, redesign requirements and other issues, and have delayed construction and completion of nuclear plants in a number of countries.

In the same category are policy mandated public enquiries. The uncertain outcome and possible complexity and length of public inquiry processes may further add to the list of uncertainties.

There is a difference between ordinary market uncertainties and uncertainties induced by government policies. Investors perceive market uncertainties, such as fluctuations in fuel prices and reservoir levels, as being easier to manage than uncertainties that stem from sudden policy changes. Some investors may adopt a wait and see strategy in response to the risk of policy changes; others may increase premiums on their investments. Both attitudes can affect new construction and LTO initiatives and push up market prices [21].

Social risks

Social risks relate to issues with the public as a stakeholder. The tide of public acceptance could turn, to the point of undermining the viability of a nuclear power generation or LTO project during or even after the implementation phase. The general public and other stakeholders could, for example, react to perceived radiological risks by setting acceptance requirements for NPPs that are difficult to meet. Social risks can be mitigated by drawing on experience. Barring unforeseen and extreme events in the area of public support, nuclear power utilities have generally been able to successfully deal with questions of public concern. In many countries, operators have achieved public support by demonstrating strong operating performance and by offering local incentives, including jobs and job training, participation in infrastructure and economic growth. Social risks can be reduced by taking into account all concrete commitments offered to community support programmes and by surveying the general sentiment towards nuclear power development initiatives in the area. The national industry safety record, however, remains the basis on which policy makers have been able to point to nuclear power generation as an important response to the imperatives of energy security and environmental protection.

Contingencies

To cover all unknown risks and those that are difficult to quantify, an overall contingency allowance is normally allocated. Deterministic or probabilistic methods can be used to estimate such contingencies. Deterministic methods usually assign extra costs to the base cost estimate (BCE) to take into account risks and uncertainties. The amount is estimated based on historical records, on expert judgement, or by comparison with other projects. It may be set as a percentage of the BCE or as a percentage of the specific activities associated with the uncertainty. The BCE percentage is usually higher during the initial project stages and then lower when more information becomes available. Regardless of the availability of new information, the estimates of contingency risks (probabilistic or otherwise) should be periodically updated. Due to their inherent empirical character, deterministic methods tend to overestimate the contingency reserve.

Probabilistic methods are better suited to deal with uncertainties. They provide less conservative and more reliable estimates of the costs associated with contingent risks. They can be applied to an LTO portfolio of a fleet of NPPs and allow the evaluation of the risk profile of the entire fleet, and hence of the overall profitability of its entire LTO programme.

To help initiate a formal risk factor database, Table 2 contains a sample of a generic checklist of risk factors that may have an economic/financial impact on an LTO project. The list can be expanded or adapted to the specific conditions of each NPP.

More information on the feasibility study of which the risk assessment is a part can be found in Appendix III.

4.2. INTEGRATED QUANTITATIVE RISK MANAGEMENT PROCESS

As discussed above, structuring an NPP LTO project for success requires the identification, understanding and control of all the various risks associated with the project (including contingencies) and of their potential impact on an NPP's technical and economic performance.

Any risk management process should always be a 'live' undertaking, because projects and plant operation themselves are live undertakings. The inputs to the risk models should thus be periodically updated. An up to date risk model allows the owner/operator and the other major stakeholders to be aware at all times, and in an integrated manner, of the health of the project and of the current project risks. In addition, a live risk management process allows the project managers to effectively react to unexpected events in time and on budget, while dramatically reducing uncertainties.

An effective integrated risk management process requires adherence to three crucial conditions:

— All project stakeholders must be involved in providing input to the risk model;
— For each risk, a specific risk owner must be named and the related responsibilities well defined;
— The risk owner must have both the capability and the authority to manage the risk indicated by the model outputs, particularly the schedule risks and the risks related to budget overruns and plant performance.

An integrated quantitative risk management process of a complex LTO project suggests the use of a probabilistic approach. This kind of approach applied to decision making was first described in WASH-1400 [24]. Probabilistic techniques can tackle complex correlations with many unknown variables and define the best paths to take. They offer an unprecedented degree of confidence in dealing with risk. In the IAEA's publication on probabilistic assessments [25], the probabilistic techniques were systematically documented, together with their quality requirements commensurate with nuclear power applications. One of the first areas where probabilistic methods were applied in the nuclear industry was the safety engineering area, where the techniques were applied to the design of safety systems. The application was called PSA and it was implemented as a tool to support the selection among all design options of the one with the best safety and reliability performance, within the project boundaries. Similarly, probabilistic techniques were later applied to operational environments, but there the focus changed. The main risk categories shifted to ageing and failure modes and to maintenance optimization. They were more probabilistic risk assessments. Probabilistic techniques are now also being used in the advanced techno-economic approach to manage risk.

TABLE 2. CHECKLIST OF RISK FACTORS OF A GENERIC LTO PROJECT

Risk factors	Detailed risk items
Technical/management	— Inadequate maintenance upgrade programmes/strategies — New or unexpected ageing management issues — Supply chain issues or loss of vendor or supplier support (e.g. obsolescence, lack of spare parts for LTO, etc.) — Insufficient waste disposal facilities, inducing over-budgeted costs in midstream for additional waste and fuel disposal — Loss of qualified personnel — Insufficient training programmes
Project	— Design or installation errors and rework — Erroneous estimates — 'Soft' pricing by vendors (budget versus firm) — Low field productivity — Change orders (e.g. scope/contract changes) — Material/equipment inspection/rejects (changes driven by quality assurance/quality control) — Overly stringent component specifications, requiring renegotiations and rework — Unforeseen R&D requirements — Late deliveries of materials/equipment infringing on the critical path — Labour relations issues, strikes/sabotage — Impact of excessive wage settlements — Contract structure and terms, including schedule, contractor coordination, division of responsibility, management issues, etc. — Project interferences, delays/deferrals — Project management issues (weak/inexperienced management team) — Insufficient bulk material quantities or adjustments
Business/economic	— Changes in energy market conditions — Change in NPP ownership, change of investors, changes in management, etc. — Poor/inadequate long term electricity price contracts — Poor/inadequate long term fuel contracts — Insufficient knowledge management programmes — Insufficient/inadequate decommissioning fund — Assumed cost (historical data vs. recent quotes) — Impact of changing interest rates — Inflation fluctuation — Currency fluctuation — Impact of liquidated damages — Late start penalties

As in all projects, the first step in LTO assessments is the identification of the LTO project risks, followed by the quantitative evaluation of the probabilistic impact of each risk on the total cost, its duration and its profitability. An LTO project that has implemented an integrated quantitative risk management framework can apply it to the traditional two blocks of LTO activities:

- The first block includes the three phases of LTO project initiation:
  - Phase I, comprising the feasibility assessment and the project scoping;
  - Phase II, consisting of the detailed evaluation, the engineering and licensing application;
  - Phase III, encompassing the project implementation (installation, commissioning).
- The second block is the LTO itself, namely the NPP extended operation period, with its specific sets of risks.

An integrated risk management process applied to the LTO project phases provides a measure of protection for the target profitability and allows control of the costs and project schedule. The process, applied to the period of extended operation, allows a higher degree of confidence that the target level of cash flow will be generated. The following two sections illustrate the risk management process as applied to the two blocks of activities: the three project phases and the operational phase.

4.2.1. Integrated quantitative risk management process for the project phases

An integrated risk management process set up during the early stages of an LTO project should remain live until the period of extended operation begins.

The risk management team is normally responsible for the following:

— Collecting risk related information from similar past projects, if available, and complementing it with information on specific risks identified by the team experts, by the various discipline experts and by the main project stakeholders.
— Formally listing the collected project risks. A risk register should be initiated and updated periodically.
— Linking each risk category to cost drivers.
— Evaluating the probabilistic impact of each risk on the cost, duration and technical performance of the project and its profitability. Project profitability indicators, typically the NPV, the internal rate of return (IRR), etc., can be used to provide a measure of the project's economic feasibility.
— Identifying the risk limits and, if limits are exceeded, promoting the development of risk mitigation measures.
— Running a CBA to facilitate decisions on which mitigation measures are more effective and worth implementing.
— Continuing to monitor the project risk profile in order to allow prompt interventions to correct risk spikes with new mitigation measures, as needed.

The process closes each periodic iteration with an analysis of all threats in all risk categories, including technical, business, managerial, financial, political, social and regulatory, as well as unknown risks and contingencies that may have an impact on the LTO project [26].

Integrated risk management can manage a portfolio of projects to evaluate the risk profile of the entire portfolio and its total earnings before interest, taxes, depreciation and amortization risk (EBITDA@risk) to make managerial decisions in terms of the following risks for an entire portfolio (see Fig. 2):

— Project_Capex@risk;
— Project_schedule@risk;
— Operation_performance@risk;
— NPV@risk.

Risk has to be managed from the very beginning of each project and throughout all its phases, with coverage of crucial activities, such as permitting, local acceptance, technology choices and contractual structures, with a wide variety of different scenarios in terms of client/supplier relationships.

4.2.2. Quantitative risk management process in the operating phase

Prior to or shortly after entering the period of extended operation, a dedicated operational risk management process should be established to help increase the probability that the plant meets its target performance and the expected economic results. As for the project phase, the operational risk management process is a quantitative probabilistic approach aimed at evaluating the impact of the operational risks on KPIs and on financial goals.

The first step in operational risk management is to define a list of risks from events such as unplanned shutdowns, load following requests, and unplanned (or corrective) maintenance that could affect the extended operation of the NPP. The second step is to measure the impact of the defined events on KPIs and then compute their probabilistic impact on earnings before interest, taxes, depreciation and amortization (EBITDA). Should the

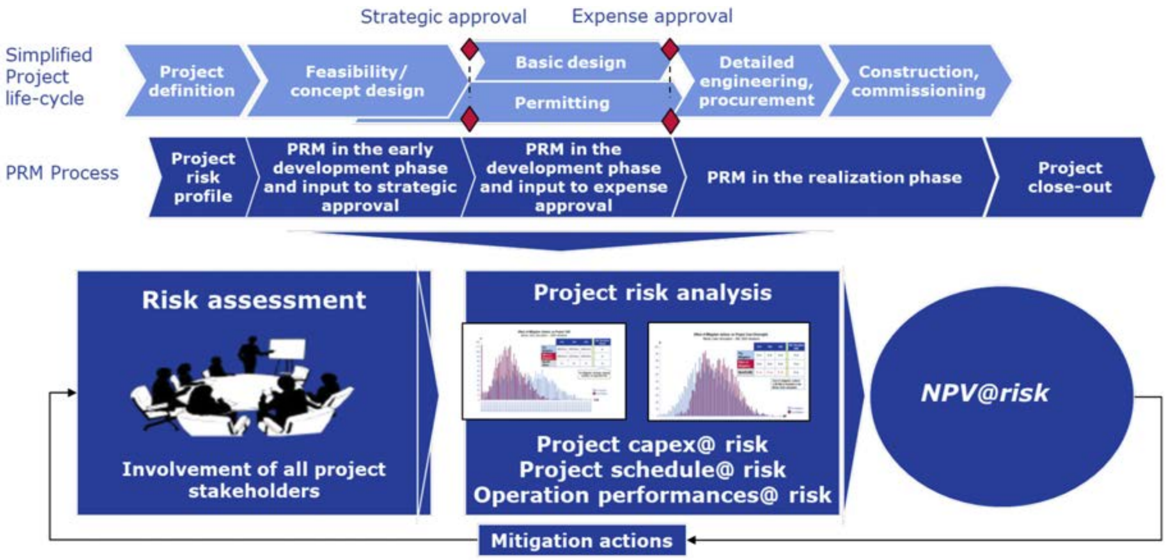


FIG. 2. End to end coverage of the project life cycle. NPV — net present value; PRM — project risk management.

impact be unacceptable, mitigation measures should be defined to reduce the overall operational risk profile of the NPP's extended operating period.

The integrated quantitative probabilistic risk management approach also allows the definition of a risk limit and hence facilitates the managerial task of controlling profitability simply by finding ways to conform to such a limit. An example from the maintenance management area could serve as an illustration of the benefits of using this approach. Spare parts for the plant can be calculated using this probabilistic approach, which is best suited to yield the configuration with the lowest risk of disrupting production and to provide the confidence necessary to forego the need to purchase costly business interruption insurance.

In general, an integrated quantitative probabilistic risk management system allows the owner/operator to make an informed decision on whether to retain any given risk and manage it internally or to transfer it to the insurance market. Even if insurance coverage for a given risk is the selected option, the risk management process can facilitate optimization of the coverage and suggest the most convenient features for the insurance contract.

With an operational risk management framework, it is also possible to manage the risk profile of an entire fleet of operating NPPs and of their LTO programmes by optimizing the timing, budgeting and capital allocation of each reactor unit in the fleet.

It is essential to select the best industrial mitigation plans and measure the extent of their efficiency in terms of risk reduction versus costs to measure the positive effects of different mitigation plans related to EBITDA (see Fig. 3).

4.3. RISK MODELLING

This section covers the tools available in the risk assessment processes described in the preceding sections. The tools (many of which are computer programs) provide a rational and systematic way of quickly assessing the unknown variables important to a project and help draw the appropriate conclusions.

4.3.1. Decision tree analysis

Decision trees help identify a strategy most likely to reach a specific goal. Decision trees and their closely related influence diagrams are used as visual and analytical decision support tools. A decision tree is a graph of decisions and of their possible consequences, including the chance of event outcomes, that can be calculated to the resource costs and the values (called utilities) of competing alternatives. Three types of nodes may be used:

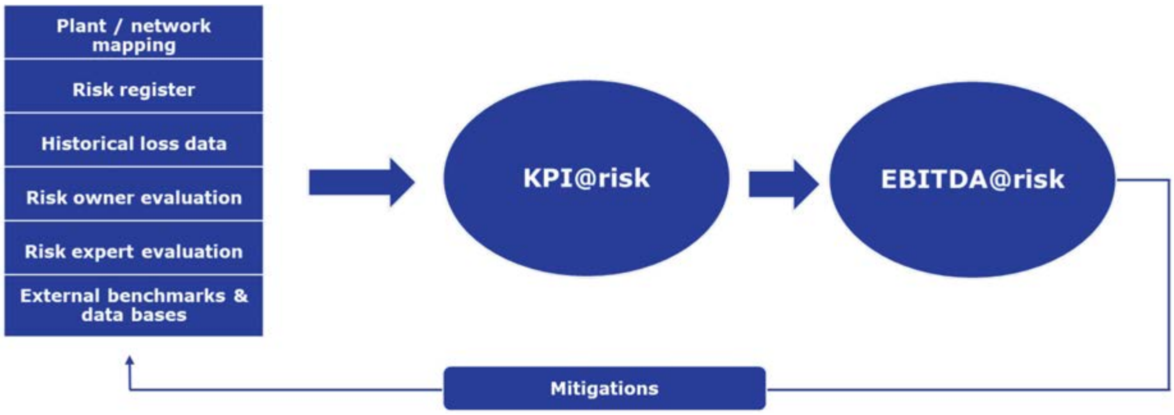


FIG. 3. Risk management of plants in operation. EBITDA — earnings before interest, taxes, depreciation and amortization; KPI — key performance indicator.

— Decision nodes, commonly represented by squares;
— Chance nodes, represented by circles;
— End nodes, represented by triangles.

Decision trees provide an effective structure within which to lay out options and investigate the possible outcomes of choosing those options. They also help form a balanced picture of the risks and rewards associated with each possible course of action.

A full analysis of the possible consequences of a decision can be achieved by producing a decision tree, since it provides a framework to quantify the values of outcomes and the probabilities of achieving them. A decision tree is one way to display an algorithm.

As with all decision making methods, decision tree analysis should be used in conjunction with experience feedback, lessons learned and common sense. If decisions have to be taken with no possibility of return and with incomplete knowledge, a probabilistic model should be used, as described below.

4.3.2. Probabilistic approaches in the risk analysis of long term operation projects

A forecast model based on historical data, on existing R&D knowledge and on experience may be insufficient. Assumptions will have to be made. While assumptions based on existing data and on experience may be useful in getting a first indication of possible outcomes, they contain inherent uncertainties and high risks in their predictions of future developments. Project costs are typical of such uncertainties. Different circumstances and different political and social contexts and obstacles of various types may easily skew cost predictions.

Instead of a single value, it might be possible to create a more realistic picture of what might happen in the future by using a range of possible values. When a model is based on ranges of estimates, the output of the model will also be a range. In a financial market, it might be possible to know the distribution of values through the mean and standard deviation of returns. The most comprehensive approach that takes into account a wide range of uncertainties in key risk areas is a probabilistic based assessment. Probabilistic techniques are powerful tools to give insights into the impact of risks, specifically on large investments such as those in the power generation field.

To incorporate probabilities in risk analysis, one or more of the variables (e.g. quantity, cost) must be replaced by distributions. Distributions define the likelihood of various values throughout a range. If all values are equally likely, then there is a uniform distribution. If a minimum, maximum and a most likely value can be identified, then a simple triangular distribution can be used.

A useful distribution for representing many processes is the so-called normal distribution. This follows a bell-shaped curve, with values concentrated in the centre and decreasing on either side. With such a curve, there is a lower probability of picking extreme values, as with some other distributions. Because the bell-shaped curve is symmetric, the probability of deviations from the mean value is comparable in either direction.

Applying probabilistic methods and a continual evaluation process to an adaptive management structure capable of applying corrective measures wherever needed will most likely lead to cost-effective large component replacements/refurbishments/modernizations and successful LTO projects.

Commercial risk analysis software is available that will calculate the outcome of hundreds or even thousands of possible scenarios and extract results. Each new calculation is called an iteration of the model, and a simulation is the collection of all iterations. Many of these computer programs use Monte Carlo simulation modelling techniques, which run the simulation by substituting random sample values for the uncertain variables (e.g. quantity and cost) [26]. The random values are generated based on their likelihood under a specific distribution [27]. Regardless of the risk analysis method used, the project objectives should be verified at regular intervals through monitoring, measurements or assessments.

4.3.3. Probabilistic simulations in risk assessments

The most popular method used in the PSA of large projects is the Monte Carlo simulation. This technique can be used in a variety of fields. It has proven to be a particularly powerful tool when applied to a project faced with uncertainty, ambiguity and variability. Furthermore, it performs risk analysis by substituting a probability distribution for any factor that has inherent uncertainty. It produces distributions of possible outcome values and builds models of possible results, also providing the probabilities that each outcome will occur.

The most commonly used probability distributions are:

— *Normal or bell curve distribution.* This distribution is symmetric and describes many natural phenomena. The user defines the mean or expected value and a standard deviation to describe the variation about the mean. Values in the middle near the mean are most likely to occur. Examples of variables described by normal distributions include inflation rates and energy prices.
— *Log-normal distribution.* In this distribution, values are positively skewed. It is used to represent values that do not go below zero and have unlimited positive potential. Examples of variables described by log-normal distributions include real estate property values, stock prices and oil reserves.
— *Uniform distribution.* All values have an equal chance of occurring. The user simply defines the minimum and maximum. Examples of variables that could be uniformly distributed include manufacturing costs or future revenues from sales of a new product.
— *Triangular distribution.* The user defines the minimum, most likely and maximum values. Variables that could be described by a triangular distribution include past sales history per unit of time and inventory levels.
— *PERT distribution.* The user defines the minimum, most likely and maximum values. However, values between the most likely and the extremes are more likely to occur than in the triangular distribution. The extremes are not as emphasized. An example of the use of a PERT distribution is the duration of a task in a project management model.
— *Discrete distribution.* The user defines specific values that may occur and the likelihood of each.

By using probability distributions, variables can have different probabilities of occurrence for the various outcomes. Monte Carlo simulations have several advantages over deterministic or ‘single-point estimate’ analysis. They provide:

— *Probabilistic results.* Show not only what could happen, but how likely each outcome is.
— *Quick generation of graphical results.* From the data generated, it is easy to create graphs of different outcomes and their chances of occurrence. This is important for communicating findings to other stakeholders.
— *Sensitivity analysis for all distributions.* In Monte Carlo simulations, it is easy to see which inputs affect each result the most. In deterministic analysis, with just a few cases, it is difficult to see which variables affect the outcome the most.
— *Scenario analysis.* In deterministic models, it is very difficult to model different combinations of values for different inputs to see the effects of truly different scenarios. Using Monte Carlo simulation, analysts can see which inputs were assigned which values and when certain outcomes occurred. This is invaluable for pursuing further research.

TABLE 3. PROBABILISTIC METHODS TO ESTIMATE COSTS AND CONTINGENCIES

	Probabilistic methods to estimate costs and contingencies
Monte Carlo (MC) simulation based methods	In general, MC simulation is used for probabilistic estimation of total costs when the costs of some items are uncertain. A cost model should be built and probabilistic distributions assigned to the uncertain costs. The total cost is then estimated by applying MC simulation to the cost model and sampling the probabilistic distributions. The total contingency is then expressed, e.g. by the difference between the base cost estimate (BCE) and a percentile of the distribution selected by the management team according to their risk aversion.
Parametric estimating method (PEM) [28]	PEM is used to estimate contingency based on risk parameters (e.g. level of scope definition, process complexity). A parametric estimate has algorithms or cost estimating relationships that are highly probabilistic in nature. Generally, the relationships of the outcome (e.g. cost growth) and the inputs (e.g. risk drivers) are determined by studying empirical data using methods such as multi-variable regression analysis, neural networks, trial and error, etc. A typical form of a simple parametric estimating algorithm is: Outcome = Constant + Coefficient 1*(Parameter A) + Coefficient 2*(Parameter B) +….. The outcome may be a measure of cost growth (e.g. contingency %), and the parameters are various quantified risk drivers. The algorithm can be much more complex, employing logarithmic, exponential and power series.
Range estimating method using MC simulation [29]	A type of risk analysis that combines MC sampling, a systematic cost screening of critical items, and heuristics (rules of thumb). This approach is used to establish the range of the total project estimate, including cost estimates, and to define how contingency should be allocated among the critical items. The process applies to estimates that are based on a defined scope. Should changes in scope be needed, the approximation upon which the range estimate is applied needs to be revised accordingly. The MC method requires the identification of a probability density function (PDF) for each critical item. Not all values in a range are likely to have an equal probability of occurrence, and this is reflected by an appropriate PDF. In rare instances, the behaviour of a critical item is known to conform to a specific type of PDF such as a log-normal or beta distribution, which reflects items that may skew heavily to one side of a distribution.
Expected value method [30]	A generic method used for both decision and risk management. Expected value can be expressed as follows: Expected value = Probability of risk occurring × impact (if it occurs) This method usually addresses project specific risks. The link between project specific risks and cost impacts is deterministic in nature; i.e. these risks are amenable to individual understanding and to estimating the cost impact on particular items or activities.
Reference class forecasting method [31]	Based on theories of decision making under uncertainty. To implement reference class forecasting on an individual project, three steps are required: (1) Finding a relevant reference class of past projects; (2) Establishing a probability distribution for the selected reference class; (3) Comparing the project under consideration and the reference class distribution in order to find the most likely outcome for the project.
Top-down model [32]	The top-down model classifies all costs of a new project into standard cost categories. The categories are carefully reviewed to identify all allocated contingencies. Then, these contingencies are removed from the estimate to arrive at the BCE in each category. Using the top-down model, the overall necessary contingency budget with respect to different confidence levels is determined. The approach assumes that each cost category follows a log-normal distribution that can be identified by estimating the 10th and 90th percentile values of each cost component. The BCE is usually considered the 10th percentile of the log-normal distribution.

— *Correlation of inputs.* In Monte Carlo simulation, it is possible to model interdependent relationships between input variables. This is important for representing the relationships showing how and when some factors go up and, consequently, others go up or down.

In power generation comparisons, the Monte Carlo technique simulates the impact of uncertainties on cost and technical parameters to obtain a probabilistic assessment of the risks and revenues of different power generation technologies. Input parameter uncertainty is typically modelled by a probability distribution, and the simulation is run many times for different values of the uncertain parameters, yielding probability distributions of economic indicators, such as the probability distribution of the NPV. Correlations between the different uncertain parameters can also be introduced. The resulting NPV distribution provides investors with a much richer analytical framework to assess power investments in liberalized markets.

Beyond Monte Carlo, other probabilistic methods exist that can profitably simulate the impact of uncertainties on technical and cost variables to obtain distributions of risks and revenues in specific circumstances. Table 3 [28–32] shows a collection of probabilistic methods and their use in predictive cost analysis in the presence of possible market fluctuations and contingencies.

The outcomes of the LTO risk management analysis can be part of a ‘stage-gate’ investment decision process. At each decisional gate, the information about the proposed investment is enriched by the risk profile of the project and by the volatility of the expected results.

In the final risk analysis report, it is important to clearly state the project goals and objectives and to determine the most important sources of variability. Full documentation of all inputs and of the assumptions made is essential, e.g. the initial uncertainty, the steps taken to reduce it and the residual uncertainty. The hazards, probabilities and consequences of risky situations are equally important to disclose. The results of the analysis should provide a means to compare a variety of plans, each with the inherent risks associated with it.

In conclusion, project risk management represents a powerful way to support the decisional process for LTO at different managerial levels and during its various phases.

If the risk analysis outcomes are not satisfactory, a mitigation plan should be developed for those risks exceeding their acceptable limit. Mitigation measures can be physical, such as physical barriers or restoration projects, or administrative, such as procedural, regulatory, corrective action or training. Each mitigation measure should be defined from both the technical and economic point of view and its effects evaluated in a quantitative probabilistic way. The final mitigation plan should be subjected to a CBA inclusive of risk factor considerations.

More information on risk assessment in economic analysis is presented in Appendix IV.

5. ECONOMIC ASSESSMENT OF LONG TERM OPERATION

The economic analysis of an LTO project is concerned with profitability, but it is profitability from the owner/operator point of view and it is linked primarily to the return the project can provide, compared with the returns from other options.

Several figures of merit are used in LTO assessments to evaluate the economic performance of a project relative to its alternatives in order to provide decision makers with actionable information. The calculation of economic figures of merit is based on the costs and revenues attributable to the design, construction and operation of a power plant for its licensed lifetime. Costs are entered as inputs taken from market prices and are usually divided among the various LTO project activities, such as design, procurement, refurbishment scope, operation, fuelling and decommissioning. Revenues come from selling the electricity output produced during the LTO period at electricity market prices.

The economic figures of merit should be investigated in depth by taking into account the risks/uncertainties facing the project and by subjecting to sensitivity analysis the major economic parameters such as investment, discount rate and carbon dioxide pricing (where applicable).

If a preliminary economic assessment shows unacceptable figures, the cost inputs could be challenged through a break-even analysis using the total target cost that would warrant the economics of a project. A break-even analysis may be helpful in scrutinizing the initially assumed physical inputs and their prices. Through this process, the cost inputs can be optimized without compromising the safety standards and the expected plant reliability and economic performance. The process is shown in Fig. 4.

The project management team should convey the economic assessment results to the owner/operator, who may disclose them to other stakeholders. Confidentiality is normally strictly required. To help control leaks, confidentiality statements are signed by all participants and only the owner/operator or one representative, supported by a limited number of specialists, manages communications externally to the project.

5.1. PURPOSE AND SCOPE OF THE ECONOMIC STUDY FOR LONG TERM OPERATION

The total generating cost for LTO has in the past been lower than the cost of other sources of electricity. However, recent market deregulation policies, plant improvements following the Fukushima Daiichi accident and new regulations for nuclear energy have added significant commitments, particularly on older plants initiating LTO projects. The additional capital expenditure has influenced the cost of nuclear power generation from LTO. The economic factors that need to be reviewed are:

- The required capital investment to upgrade the safety level, the increased robustness of the core systems and the expected increased flexibility of the plants in the face of extreme external events;
- The potential increase of O&M costs;
- The possibly insufficient storage capacity of low and intermediate level waste and of spent nuclear fuel that may be required to implement the upgrades;
- The potential increase of annual disbursements into the national decommissioning fund;
- The increased volatility of electricity market prices.

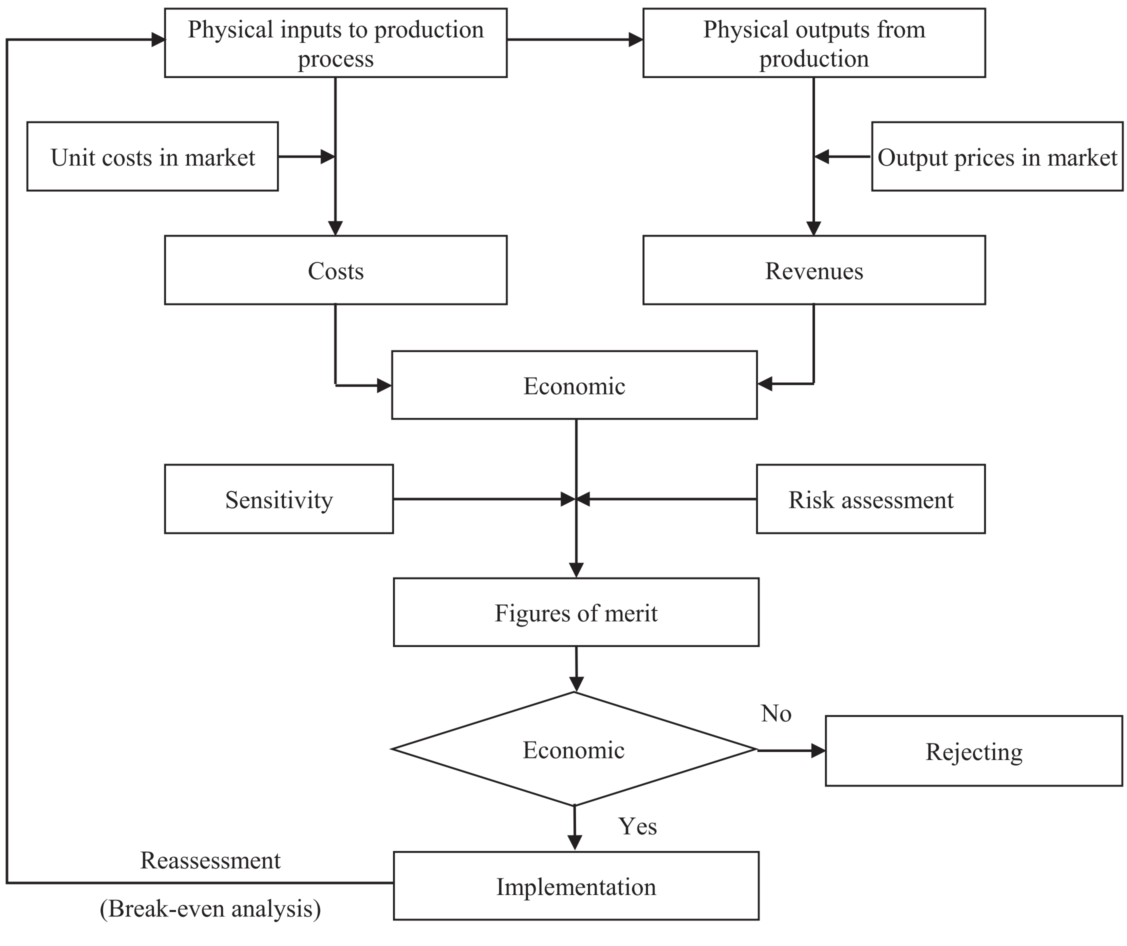


FIG. 4. Flow chart for the economic assessment of long term operation.

These added economic burdens and risk factors may substantially decrease LTO option plant profitability with respect to the projected wholesale electricity market price. The major focus of an economic assessment for LTO of an NPP will be to:

— Evaluate the facts and circumstances that define the boundary conditions for the economics of LTO;
— Identify scenarios that might lead to loss of competitiveness of power generation from LTO;
— Assess the risk of early closure, i.e. stopping operation before LTO is completed;
— Perform sensitivity analyses for the relevant parameters with the highest identified risk;
— Determine the long run marginal cost[7] of electricity from LTO as the economic indicator to justify investing in strategic upgrades.

As mentioned earlier, the LTO programme should be established well before the last five to ten years of the originally assumed plant design life, and include the plan of LTO related activities and a comprehensive techno-economic assessment.

To build the cost driver matrix and determine the LTO economic implications, their financial impact and ultimately the project's viability, the following information is required:

— The installed capacity of the plant.
— The net capacity of the plant (installed capacity minus station load).
— The plant capacity factor, based on the recent operating history.
— The maximum quantity of electricity generated in a year, as the average net generation of the recent operating history.
— The unit sale price of electricity.
— The start date of the project.
— The project completion date.
— The duration of the LTO extension beyond the originally assumed service time.
— The timeline for project implementation, including the detailed activities required to design and implement all approved LTO modifications.
— The reference currency unit used and the exchange rate of the local currency versus the reference currency (if applicable).
— The yearly inflation and its impact on the sale price of electricity.
— The sources of local and foreign finances.
— The interest rate on the borrowed capital.
— The discount rate or rates and all cash flows discounted to the base year.
— The project feasibility assessment for the evaluation period and financial requirements.
— The estimate of annual recurring expenditures after project completion. Recurring expenditures may include:
  • O&M expenditures;
  • Fuel cost;
  • Heavy water cost (if needed);
  • Spares and consumables;
  • Office administration expenditures;
  • Decommissioning fund;
  • Waste management funds;
  • Management programmes;
  • Training, qualification, etc.;
  • Human resources;
  • Additional spare parts;
  • Additional services, transportation, etc.

[7] The long run marginal cost of electrical generation is defined as the levelized cost increase of meeting a marginal increase in demand with all the variable production factors over an extended period of time. It is calculated by determining the difference in the NPV of two optimal generation development programmes over an extended period (say 30 years).

5.2. ECONOMIC ANALYSIS TO SUPPORT THE DECISION FOR LONG TERM OPERATION

NPPs represent a technical and financial asset with strategic significance for both the owners/operators and the country. The final decision to implement LTO for each NPP in the country rests with the government authorities in consultation with the owner/operator and the main stakeholders, with full regard for the electrical power system strategy of the region and in conformity with the broader energy supply objective of the country. For example:

- Ensuring adequate supplies to meet demand;
- Minimizing the costs of electricity, including environmental costs and carbon taxes (if applicable);
- Ensuring the equitable treatment of both electricity consumers and plant owners in a fair cost recovery scheme;
- Responding to intensifying electricity market pressures.

However, the responsibility for implementing the decision and meeting the safety and performance targets for the service life extension of an NPP beyond its originally assumed design life lies with the owner/operator. From an economic standpoint, the operating life of a nuclear unit is determined primarily by its profitability rates, relative to other available generation options, such as the economic evaluation of alternative replacement projects and the decommissioning of existing asset(s). A proper economic assessment should include an analysis of the entire power system, which involves a current value comparison between the LTO power generation option and that of replacement power. Replacement power alternatives may include:

- Nuclear, conventional and renewable power sources;
- Power purchases from power exchange contracts;
- Contracts with independent power producers;
- Demand side management.

Other elements are also of primary importance in any decision on power generation:

- The cost of replacement energy during nuclear plant outages;
- The corporate financial situation, and the accounting policies;
- The typical uncertainties of an LTO project, such as the long planning horizon and the licensing lead time;
- The economic dependence dictated by the electricity market structure (e.g. regulated or deregulated markets) and by a variable power generation system (e.g. the substantial presence of renewables, storage);
- The lead time of a replacement capacity project, if required, and the length of the LTO period.

It is important to recognize that the assessment of an NPP's economic life and hence an LTO decision, is plant specific. Each NPP has its own unique history of costs and performance. Large year to year fluctuations in costs are common for most nuclear plants, as projects requiring capital additions are undertaken and completed. Plant availability also varies from year to year. Low electricity demand periods and unplanned repair outages contribute greatly to cost and performance fluctuations. The unique circumstances of the plant and the grid influence cost and performance, but also the value of electricity in the country and future demand. Three types of NPP costs can determine the economic life of individual units:

- Historical capital costs;
- Future capital additions (for regular operating time and for LTO);
- Annual O&M and fuel costs.

Depending on the results of the specific reactor unit assessment and of the power system analysis, the owner/operator will select the optimal development scenario and the time interval. The optimization will be based on meeting the demand for electricity at the minimum possible cost, conditional on a set of financial, technical, environmental, political and resource constraints.

5.2.1. Economic analysis methodology for long term operation

In most cases, the decision to continue operating an existing plant can be based on its marginal generation cost in comparison with the marginal generation costs of other options. Marginal generation cost includes the marginal costs of operation, maintenance, fuel cycle and LTO investment amortization. In regulated electricity markets, marginal costs have been lower for NPPs than for most alternatives and LTO has been in most cases an attractive option from an economic viewpoint.

Since the 2000s, deregulation of electricity markets has been an increasing trend. Deregulation increases competition, removes monopolies and eliminates guaranteed sales at fixed rates, traditionally imposed by government authorities. To compete in a deregulated market, owners/operators endeavour to reduce their total operating costs.

5.2.1.1. Cost concepts

There are different types of cost concepts, each applicable in its proper context: bookkeeping cost; opportunity cost; average cost; marginal cost; sunk cost; investment cost; O&M cost; fuel cost; operational cost; decommissioning cost; resource cost; fuel cycle cost; refurbishment cost; private cost; social cost; and external cost. For all cost types, the currency and the reference year of the currency are required. Costs can also be computed relative to a reference base cost, whereby they are quoted in a particular currency, proportional to the base cost level [33].

The total cost of electricity per MW·h for NPPs consists of:

- *Private costs.* These are the costs borne by a power plant owner and that show up in the profit-and-loss statement at the end of the year. They are:
  - Investment costs;
  - Costs of site preparation for LTO;
  - Decommissioning costs;
  - O&M costs;
  - Fuel cycle costs (including the backend and long term disposal).
- *External costs or externalities.* These costs arise when the activities of one group have an impact on an unrelated party and when that impact is not fully accounted for or compensated. Some of the classic impacts from NPPs are:
  - Radioactive emissions;
  - Long term waste disposal (sometimes part of the fuel cycle; often already internalized);
  - Possible accidents and liability;
  - Risk of nuclear material proliferation;
  - Avoided carbon dioxide emissions (for an LTO project, this is a positive externality);
  - Environmental effects.

Depending on the local situation, some external costs may or may not be applicable. Those that are not should be deleted from the list.

When looking at external costs in the context of the nuclear power industry, it is important to recognize that a considerable fraction of the costs linked to the harmful nature of radioactive substances has already been internalized and should therefore no longer be considered an externality [34]. Typical examples are levies that have been and are being charged for decommissioning the plant and for interim radioactive waste management and final disposal. These are internalized usually in the form of periodic contributions to long term funds.

An element to bear in mind is the difference between the cost of nuclear electricity from the LTO of an existing NPP (for which only marginal cost and fixed O&M costs are considered) and the cost of new plants of different energy sources (for which the investment cost must be taken into account). Plants that have been built in the past, whether or not they have depreciated, are characterized by a ‘sunk’ investment cost. This means that the only costs in play remain the costs of upgrades and the operational costs [34].

If operational costs are too high in comparison with other generation options and with the market price of electricity, then owners/operators may decide to forego LTO and shut down their plant for purely economic reasons regardless of the technical and/or safety state of the plant. An example of such an early retirement took place in 2013 in Wisconsin, USA, where the Kewaunee NPP was shut down, even though it had received a Nuclear Regulatory Commission (NRC) licence renewal until 2033. It was retired because of low market prices, mostly driven by electricity generated by low cost shale gas.

In other markets and circumstances, it may make economic sense to continue the operation of existing plants beyond their originally assumed design life, even if major refurbishment investments are necessary. When substantial investments are made to refurbish a plant, then a sufficiently long operational period must be successfully licensed by demonstrating to the regulator an acceptable safety state for the plant at the end of the LTO period. The possibility of changes in future regulatory requirements must also be taken into consideration in LTO related studies. Government guarantees with possible contractual compensation should be sought in the case of a premature shutdown caused by changes in the regulatory requirements during the LTO period.

Any investment always competes with other possible investment choices. This is sometimes represented by comparing the economic cost with the opportunity cost, which is the cost of the best foregone alternative. This comparison can provide a measure of what has been given up, when a decision is made. This is of particular interest to private investors. It is important to recognize that a private investor's viewpoint on cost may be different from that of a public investor, or that of a private concession holder in a regulated market.

Other than deregulation, the electricity generation market is currently undergoing a substantial evolution on its path towards a zero carbon dioxide emission target, which is increasingly becoming a policy trend in many countries.

The LTO option may help in this transition phase, since it offers an interesting economic strategy in line with a carbon dioxide free electricity policy that favours renewable sources. LTO would give the electrical power sector more time to thoroughly analyse the transitional aspects of system integration with a large share of intermittent renewable generators, both decentralized and centralized, with substantial non-dispatchable overcapacity. In addition, LTO would provide sufficient inertia in the system to support grid stability.

For convenience, the costs of an NPP LTO project are usually divided into the following categories:

— *Nuclear fuel*. This is expected to include the cost of uranium and of its enrichment (if required) under the existing contract with the fuel supplier. For CANDU type reactors (PHWRs), there is no enrichment cost, but the cost of the heavy water inventory should be added.
— *Water tax*. This is, in most cases, a local government tax for drawing flow from bodies of water for cooling purposes.
— *Materials and services*. These are the costs of the services provided at the NPP (e.g. planned and unplanned maintenance, production support) of the materials used, such as spare parts and consumables, portable tools, instruments, etc. Excluded are salaries, benefits and the cost of fuel.
— *Depreciation charge/investment costs*. This cost line represents the amount relating to the repayment of the principal debt (if any) and the sum of the investment expected to be made in a specific year, including the purchase of small assets such as furniture, re-roofing, etc. (as stated in the long term investment plan).
— *Insurance*. This item includes all insurance costs (both nuclear and non-nuclear) associated with NPP operation.
— *Salaries and related costs (labour costs)*. This covers basic salaries of NPP employees, along with social contributions, and any other benefits such as pension payment contributions, health and life insurance costs, etc.
— *Compensation to local communities paid directly by the NPP*. This represents the compensations and contributions that the NPP makes directly to local communities in exchange for restrictions on the use of land, in accordance with legislative requirements.
— *All other expenses*. This line includes expenses incurred in the NPP management accounts for supplementary activities, such as revaluation, withdrawals and financial transactions.

The Nuclear Energy Agency of the Organisation for Economic Co-operation and Development (OECD/NEA) has published a comprehensive report on the economics of LTO [35].

5.2.1.2. Discount rate

The fact that private investors expect a return on their investment and that interest is to be paid on loans means that money has a time value, usually expressed by a discount rate, which is generally considered the 'opportunity cost' of capital. In other words, cost varies both in time and geographically.

The discount rate is defined as the rate of interest reflecting the time value of money that is used to convert benefits and costs occurring at different times to equivalent values at a common time.

Benefits and costs are worth more if they are experienced sooner. All future benefits and costs, including non-monetized benefits and costs, should be discounted. The higher the discount rate, the lower the NPV of future cash flows. NPV is the difference between the present value of cash inflows and the present value of cash outflows. For typical investments, with costs concentrated in early periods and benefits following in later periods, raising the discount rate tends to reduce the NPV.

Discount rates can be calculated by finding the WACC:

$$\text{WACC} = r_d \left(D/V\right)\left(1-t\right) + r_e \left(E/V\right)$$

where

r_d is the interest rate on debt;
r_e is the expected rate of return for shareholders;
V is the total volume of capital to be covered;
D is the amount of debt;
E is the amount of equity;
t is the corporate tax rate.

WACC is the cost of capital considering tax reductions for debt in general accounting systems. In this part of the study, from an economic cost viewpoint, a pre-tax WACC has been used. Therefore, the above equation was modified as follows:

$$\text{WACC} = r_d \left(D/V\right) + r_e \left(E/V\right)$$

Among the factors that make up WACC, the most difficult to obtain is r_e, which is composed of a risk free interest rate and risk premium. The risk premium is added to the risk free interest rate because a higher r_e is needed to make the risk specific to a project acceptable to an investor. The risk premium is usually calculated by using the capital asset pricing model, which is beyond the scope of this study.

As a quantitative example, to give a sense of the magnitude of r_e, realistic assumptions on the inputs to WACC could be made. For example:

— r_d = 5%.
— The debt and equity ratio is 50/50.
— 3% of the risk free rate. A government bond rate could be used as a risk free rate because there is almost no risk of default in countries with stable governments.
— 6.2% of risk premium.
— r_e = 9.2% with these assumptions.

In general, r_e is higher than r_d because there is a difference in risk between equity and debt for lenders. Risk is less in debt than in equity from the viewpoint of lenders. This is mainly because debt carries a higher level of importance in the event of bankruptcy. Equity is in fact normally wiped out in bankruptcy. With these assumptions on input values, the WACC is calculated to be 7.1%.

The nominal discount rate is the typically stated discount rate. It does not consider inflation, namely fluctuations in the value of money that may occur over time. When inflation is taken into account, a more realistic sense of the purchasing power of money in the future is obtained.

Because WACC is expressed in nominal value, it could be translated into real value by using the relationship between the real and nominal value:

$$(1+i) = (1+r)(1+f)$$

Here, i is the nominal discount rate, r is the real discount rate and f is the inflation rate. If we assume the inflation rate is 2%, the WACC in real value is 5%.

According to Ref. [36], a 3% real discount rate is appropriate for government owned utilities or those with a regulated stable rate of return and fuel price increase allowances. A 7% real discount rate is appropriate for an investor such as an electric utility in a regulated market or a private investor investing in a low risk technological option under low risk of default in a stable environment. A 10% real discount rate is recommended for an investor facing substantially greater financial, technological and price risks.

In trade, prices and costs of goods and services are expressed in monetary terms. When inflation plays an important role in a country, the purchasing power of money is reduced in time.

In practice, when costs are expressed in constant terms, the real discount rate should be used to consider changes in the real value of money over time. When costs are expressed in nominal value, which includes inflation factors, then the nominal discount rate should be used instead.

Future costs incurred in period 1 (C1) with inflation rate f are brought back to the present point in time as follows:

$$\mathrm{C1}(1+f)/[(1+r)(1+f)] = \mathrm{C1}/(1+r)$$

Whether or not the future value is discounted to the present time makes no difference to the NPV because the same discounting is also applied to benefits. On the other hand, it would make a significant difference in LCOE calculations. This is because although using it would make no difference to the cost part of the LCOE calculation, it would make a significant difference to the electricity generation part, since the latter is spread out over time. Consequently, the approach adopting inflation and nominal discount rates will change the LCOE value.

It should also be noted that the nominal discount rate, which does not take into account the inflation rate, is useful in financial analysis to estimate the amount of net income accrued to a company. This is because the taxation rate greatly affects the net income of a company and tax is based on income expressed in nominal values.

5.2.1.3. Economic comparisons: LCOE

The objective of an economic and financial analysis of an LTO proposal is to find answers to various questions related to the viability of an LTO project. These questions could be quite diverse, depending on the specificity of each case. Typical questions to consider are:

- From an economic point of view, how does LTO of an NPP compare with other electricity generation alternatives, including building a new NPP?
- What are the estimated costs and benefits from expected performance improvements, including power uprates, if applicable, in the context of LTO implementation?
- What would be the optimum length of life extension for an NPP?
- What would be the financial consequences of LTO on the utility/company's business?

In order to find the appropriate answers to these questions, a comprehensive evaluation, based on economic and financial analyses, should be conducted that compares the LTO proposal against other electricity generation alternatives. Figure 5 shows a process for conducting an economic and financial assessment of LTO. It includes:

- Data preparation for both LTO and other alternatives:
  - Economic data, e.g. investment, fuel cost, operation cost, construction time and schedule and project life;
  - Operation data, e.g. capacity factors, fuelling, outage and estimated production;
  - Fiscal and financial data, e.g. inflation, exchange rates, interest rate and taxation.
- Analysis and evaluation:

- Determining the NPV and the LCOE of LTO and of its alternatives;
- Defining and evaluating the economic value of LTO and of its alternatives, and ranking them according to various performance indicators;
- Conducting a financial analysis for an LTO proposal and alternatives;
- Performing a sensitivity analysis and identifying the high negative impact (risk) aspects;
- Conducting a risk assessment and defining mitigation strategies (see Section 4).

Among the alternative options of fuel generation are solar, wind, biomass, combined cycle gas turbines, hydraulic turbines and coal. A qualitative assessment of the selected alternative power options will require these basic data:

— Required energy output (GW h/a);
— Capacity factors;
— Required installed power (MW);
— Construction duration (from the initial decision to commercial operation).

In addition, these questions need to be considered:

— Is baseload production or load following required from these alternative energy sources?
— Is the alternative power suitable for baseload generation (is it dispatchable)?

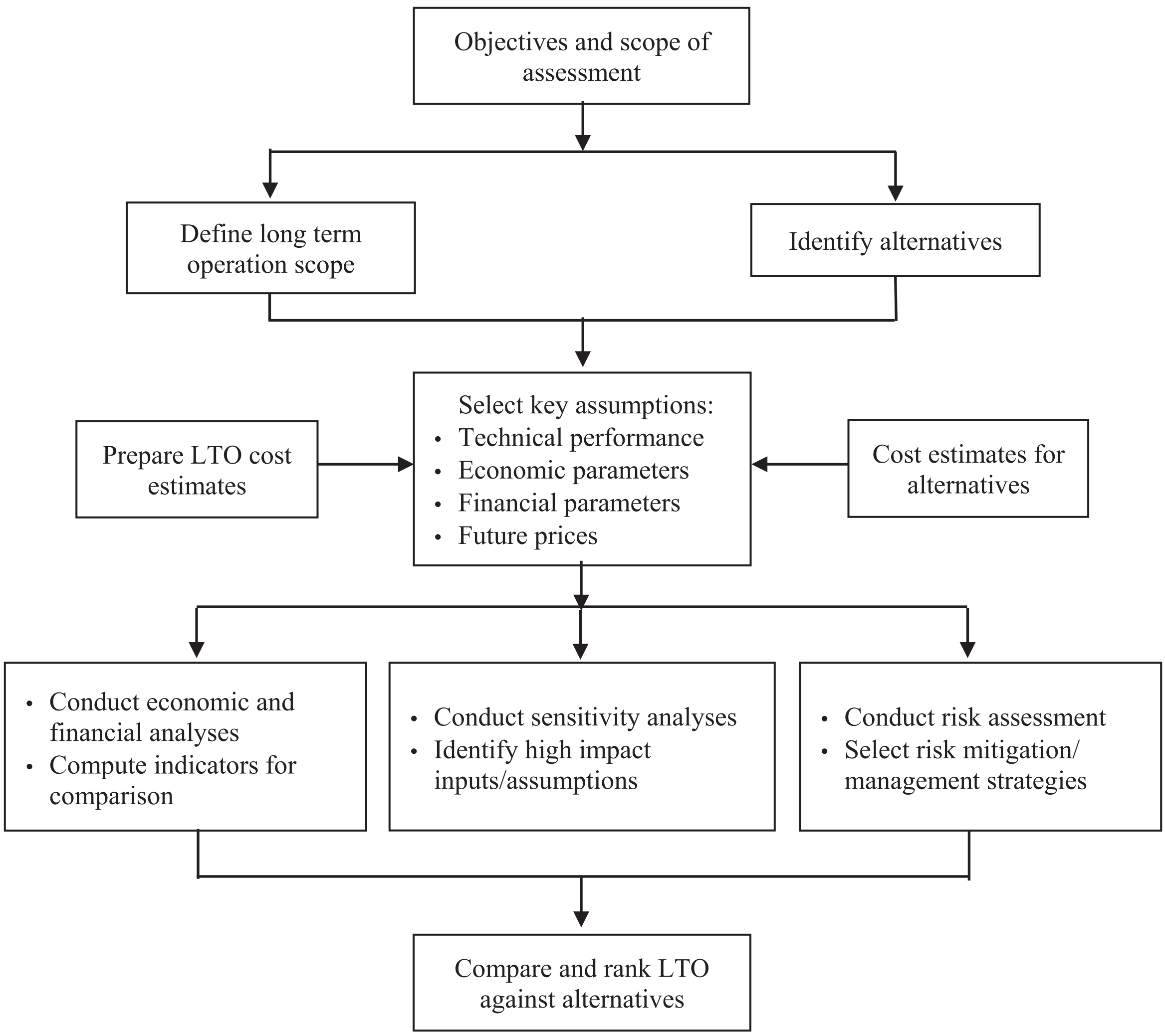


FIG. 5. Example of a process for the economic assessment of long term operation.

— Is it aligned with carbon dioxide emission policies and national targets and with other environmental policies?
— Is the option feasible within the country's technical capabilities? Is the country heavily relying on imported fuel? Is there a diversity of supply goal or policy in the country?
— Are the alternative options to the NPP in LTO providing the same degree of grid stability? There may be additional costs associated with achieving a similar level of grid stability. It is likely that the grid operators would attempt to recover these costs through grid connection charges. These costs should be taken into account when selecting alternative power sources.

For each alternative power generation option, the development period has to be stated, along with the overnight investment cost per megawatt of installed capacity. Each alternative power option should be sized to deliver a baseload similar to that of the NPPs they will replace. When comparing alternative options with LTO of an NPP, the equivalent annual electricity production based on the assumed NPP capacity factor during LTO should also be used as the required useful energy production from the alternative power options.

The total installed capacity of the combined alternative power plant sizes, if multiple plants are required, should equal the capacity of the NPP.

NPP new builds may be a viable option, under certain circumstances. If the selected nuclear power generating unit is too large for the local market, there would be a surplus generating capacity at the beginning of operation. This spare generating capacity may be sold to neighbouring jurisdictions or to a third party. The economic calculation in this case assumes that the additional CAPEX and the operating costs associated with the spare capacity will be covered by long term power purchase agreements with third parties. If it is not possible to obtain long term power purchase agreements for this additional capacity, the additional CAPEX and O&M costs associated with the spare capacity will significantly increase the cost of electricity. When considering NPP new builds, it is important to recognize that the availability of financing to support the significant investment associated with new nuclear power may be an issue, since the required large disbursement may impact the balance sheet and credit rating of sponsors.

As a simplified example of options that may be contemplated in an economic analysis, two scenarios are postulated:

— *NPP scenario 1.* NPP operation to the end of the design life, followed by decommissioning. In this scenario, the NPP is maintained and its ageing mitigated with recommended upgrades to ensure its safety and reliability to the end of its originally assumed operating life (e.g. implementation of safety upgrades as per regulatory requirements); decommissioning of the NPP commences one or more years after permanent shutdown. Alternative power source(s) are built or made available.
— *NPP scenario 2.* Full life extension to 20 years. In this scenario, an investment programme is implemented that allows the NPP's operating life to be extended by 20 years; decommissioning the NPP begins one year after the end of LTO.

A baseline cost item common to both scenarios is the sum of the NPP operating costs and of the contributions to the decommissioning fund, which are different depending on the operating lifetime of the NPPs in each scenario.

The LCOE is a widely used indicator to evaluate the cost of electricity generation (in \$/MW·h) for all scenarios. LCOE is usually higher for an NPP with a shorter operating life. The costs included in the LCOE calculation should only be those associated with the generation of electricity, not with the infrastructure requirements of the electricity grid or with transmission charges.

Other external costs outside of the plant (e.g. connections to the grid distribution system) must be considered from the viewpoint of customers. Additional transmission costs, grid infrastructure and other external costs associated with grid enhancement, grid reliability and ongoing grid stability need to be included in the analysis scope of the price of electricity to the end customer.

For all alternative power options, there is likely to be a varying degree of additional grid infrastructure and associated infrastructure costs. Among these options, there may be ongoing costs for the grid operator because alternative power options have to be connected to the grid.

The LCOE method facilitates the homogeneous comparison per MW·h of the revenue (baseload guaranteed energy, for instance) with the forwarded price of the MW·h on the wholesale market. The expected unit revenue should be homogeneous with the 'long run marginal cost' of electricity.

The general formula used to calculate LCOE (1) for all sources of electricity is:

$$\mathrm{LCOE} = \frac{\sum_{t=t_c}^{\text{Lifetime}} \frac{\left(\text{Investment}_t + \text{O\&M}_t + \text{Fuel}_t + \text{Carbon}_t + \text{Decommissioning}_t\right)}{(1+r)^t}}{\sum_{t=1}^{\text{Lifetime}} \left(\frac{\text{Electricity}}{(1+r)^t}\right)}$$

The formula for calculating LCOE corresponding to the period of extended operation $\mathrm{LCOE_{LTO}}$ is:

$$\mathrm{LCOE}_{EO} = \frac{\sum_{t=-t_R}^{t_{EO}} \frac{\left(\text{Refurbishment}_t + \text{O\&M}_t^{EO} + \text{Fuel}_t^{EO} + \text{Decommissioning}_t^{EO}\right)}{(1+r)^t}}{\sum_{t=1}^{t_{EO}} \left(\frac{\text{Electricity}^{EO}}{(1+r)^t}\right)}$$

where

EO is extended operation;
t is the duration (time);
t_c is the duration of construction;
t_R is the duration of refurbishment;
r is the annual discount rate.

Once the LCOEs of both nuclear power based scenarios have been established, any other power source option that may be available should be compared with both NPP scenarios. At this point, the costs of introducing alternative power sources should be excluded to the cost of their connectivity to the grid and the cost of any infrastructure outside the plant. Alternative power options should be selected based on their suitability as proven baseload electricity generators and availability for production from the date the NPP is assumed to cease production.

Future revenues and expenses can be determined based on actual historical data and on similar projects in other jurisdictions (if known), as well as on experience with NPP generation. The investment data should be based on indicative quotations obtained from the major suppliers.

The inputs for the decommissioning fund are based on data previously required by the regulator or by the government.

It is important to recognize that LCOE is not a complete and absolute method of assessing the economic benefits of an electricity source, for the following reasons:

— It does not adequately reflect the market realities characterized by uncertainties and dynamic pricing;
— It provides generation costs at the plant level and does not include the network costs of a power system;
— It reveals little information on the contribution of a given technology to addressing the energy delivery requirements;
— It does not account for the relative stability of production costs over the plant lifetime, and therefore the potential contribution of LTO to cost and possibly price stability.

Incentive payments are usually not included in LCOE calculations unless there is a long term contractual certainty regarding their payment.

When considering alternative power options, the power replacement scheme would probably include a mix of alternative power generation technologies, rather than a single technology. It is important to recognize that the sum of the LCOEs of the combined alternative power generation options would be higher than the LCOE of the more economically viable source if it were to be installed as a sole source. The LCOE of each alternative power option should be calculated over its stated useful economic life, regardless of the life of other options, because the LCOE indicator would equalize the differences.

If energy imports were part of the power mix options, the LCOE could be calculated over a period equal to the planned LTO. However, before relying on imports, the ability of the neighbouring jurisdiction to supply baseload electricity on a long term basis should be assessed. Additionally, in terms of price forecasts, the baseload energy price history from energy imports should also be reviewed to identify the regional electricity markets to be relied upon as sources of price data for future imports.

Historical price data in neighbouring countries can be used, though cautiously, as a general indicator of possible future prices. The best indication of short term future trends can be obtained where liquid power exchanges exist, and future prices are controlled. Many factors can influence the actual cost of imported electricity over the duration being considered in the analysis. Regardless of how prices are acquired, it is important to always consider the risk of a sudden volatility of the price of imported energy.

National policy usually affects the economic and risk analyses. Before any formal investment decision on alternative options is taken, a full review of the prevailing policy and regulatory requirements should be completed to confirm the fundamental input data used in the analysis are correct and up to date and to evaluate the associated risks.

The main parameters influencing an LTO decision are:

— High capacity factors for the duration of LTO.
— Refurbishment investment cost.
— Electricity pricing.
— Decommissioning costs.
— Discount rate.
— Elements such as carbon dioxide pricing subject to uncertain and evolving policies. When carbon policies are in force, the carbon cost per tonne of carbon dioxide produced by all selected generation technologies should be stated and be consistent with all applicable energy sources.

5.3. NUMERICAL EXAMPLE OF A HYPOTHETICAL ECONOMIC ASSESSMENT OF LONG TERM OPERATION

The economic viability of an LTO project is determined by conducting a CBA. The economic assessment of LTO usually starts with identifying the cost drivers in the three categories of technical, management and external costs.

In most cases, the economic assessment of LTO can be conducted in two stages. In the first stage, the economic assessment is carried out using only the technical and management cost drivers. In the second stage, externalities are added.

Among the many economic figures of merit, the NPV is normally considered a good indicator for an economic assessment of LTO.

In the first stage, NPV is conveniently used as a viability indicator. It is calculated as the difference between the present value of the benefit and the present value of the costs. At this stage, only private costs and private revenues are taken into account. Sometimes, if a conservative indication is considered useful at this stage, then negative externalities may also be taken into account. A positive NPV means that the benefits exceed the costs and the LTO remains an option. This allows the owner/operator to proceed to the second stage.

In the second stage of an economic assessment of LTO, externalities are added to the technical and management related cost drivers. Normally, both negative and positive externalities are added to the preliminary assessment performed in the first stage. Typical negative externalities include expenditure in support of the local community. Positive externalities may include items such as a rise in the wholesale electricity price. In addition, when operating in a carbon tax environment, the cost savings due to the absence of carbon emissions from a nuclear plant in LTO can be added as a positive externality. Sometimes externalities are recognized as being even more important than technical and management cost drivers. This means that the economic viability of the LTO is not proven until externalities in the country or region are fully added to the technical and management cost drivers.

A high capacity factor for the NPP during its LTO period and electricity prices are two of the most influential parameters in an LTO option. Sensitivity analysis is strongly recommended to test the influence of these parameters. A sound economic assessment requires familiarity with basic economic concepts, along with the capacity to evaluate correctly the economic figures of merit, such as NPVs and LCOEs.

5.3.1. Hypothetical parameter values as a numerical example

For most parameters in this hypothetical numerical example, median values have been used, as shown in Table 4.

5.3.2. Refurbishment investment cost

A large LTO cost item is the investment required for NPP refurbishment, including ageing mitigation, safety and performance upgrades. According to the European Commission, LTO and the uprating of NPPs are mostly affected by safety improvements. These large investments increase the generation cost during the amortization period by 0.2–0.6 eurocent/kW·h [35].

The economic impact of plant refurbishment associated with LTO might influence the decision to proceed. The refurbishment cost factors or drivers are primarily related to necessary licensing requirements. They represent the bulk of the LTO investments. They can generally be divided into two main investment categories:

- Initial capital investment for replacements, upgrades, uprates and so on:
  - Technological upgrades (power uprates, I&C modernizations);
  - Major replacement/refurbishment of non-safety SSCs (turbine hall replacements).
- O&M costs required to extend the operational life beyond the design life:
  - An AMP and its effective implementation for critical life limiting components;
  - Safety upgrades/improvements to meet regulatory requirements, including major replacement or refurbishment of safety SSCs.

TABLE 4. PROJECTED COSTS OF GENERATING ELECTRICITY

Parameters	Values	Remarks
Installed capacity of the plant	1343 MW(e)	Median value taken from Ref. [35]
NPP refurbishment/upgrade period		From 2010 to 2015
LTO period	10 years	From 2015 to 2024
Capacity factor	85%	Median value taken from Ref. [35]
Electricity price	\$40/MW·h	Assumed price in the wholesale electricity market for nuclear power generation
Discount/inflation rate	5% in real discount rate 2% inflation rate 7.1% in nominal discount rate	The values for the real discount rate and inflation rate were assumed
O&M cost	\$12.41/MW·h	Median value taken from Ref. [35]
Fuel cost	\$7/MW·h	Default value taken from Ref. [35]
Decommissioning cost per kW	\$648/kW	15% of the overnight construction cost. Overnight construction cost 4319 (\$/kW), which comes from the median value in Ref. [35]. Decommissioning takes place six years after the last operating year.
Spent fuel removal, disposal and storage	\$2.33/MW·h	Default value taken from Ref. [35]
Payment for the regional society	\$2 million/year	Hypothetical value

Source: Ref. [36].

Following the Fukushima Daiichi accident, regulatory requirements and voluntary upgrades recommended by stress tests and safety reviews have added to LTO related refurbishment costs. Preliminary estimates of the economic impact of post-Fukushima modifications run from 10 to 17% of the pre-Fukushima projected LTO investment.

The major post-Fukushima modifications/refurbishments that may have an economic impact on LTO are:

— Filtered containment venting for the protection of containment under severe accident conditions;
— Installation of passive auto catalytic recombiners in the containment along with hydrogen igniters;
— Enhancement of spent fuel pool cooling capability;
— Enhancement of electrical supply systems to handle conditions like loss of grid connection, extended/prolonged station blackout;
— Availability of mobile equipment for the alternative electrical supplies to power equipment, and safety I&C;
— Enhancement of I&C system functionality such that it remains capable of monitoring plant conditions in extreme environmental conditions;
— Physical protection of safety equipment against severe accident conditions (earthquake, tsunami and flood);
— Improvement in the radiological protection plan;
— Establishment of a post-accident recovery and cleanup facility;
— Enhanced equipment qualification requirement for the safety injection system.

Additionally, LTO cost drivers depend on the following conditions:

— The plant technology (design type). This cost driver is related to the safety improvements that may be required for an older technology to reduce the nuclear safety risk to acceptable levels. These safety related risk calculations have the goal of determining the optimum level of R&D expenditures to reach an acceptable level of safety, if it is not economically feasible to bring the older plant to current safety levels. The methodology used to achieve this goal is presented in Appendix I and a quantitative example of such a calculation conducted in the Czech Republic for WWER plants is presented in Appendix II.
— The NPP operating history, including the conditions of the critical SSCs.
— The type of component replacement.
— Protection from aircraft crashes and missile strikes.
— The bookkeeping method, i.e. whether the upgrades are considered proactive ageing mitigation measures as opposed to refurbishment imposed by safety reasons.
— Accounting methodologies, etc.

The OECD/NEA provides the overnight refurbishment cost of LTO in selected OECD countries [35]. They range from \$500 to \$1100/kW(e) (in 2010 dollars), reflecting the range of time spans for LTO.

The range reported by the various member countries to the OECD/NEA is wide and shows that specific investments in LTO vary considerably. Each country and each plant operates in its own economic context and under specific conditions and circumstances, such as the length of time over which the investments are spread. The reported overnight refurbishment cost also depends on whether future investments are included and on the assumptions made by the individual countries in the OECD/NEA survey. They may or may not include any of the following cost items: maintenance, refurbishment, safety upgrades, performance improvement, post–Fukushima Daiichi measures, etc.

From Table 4, the overnight cost of LTO refurbishment/upgrades is assumed to be \$700 million, equivalent to a unit cost of ~\$521/kW(e) (given a total electrical output of ~1340 MW(e)). The refurbishment cost is presumed to be spread evenly over the five year period before the start of LTO. This assumption means that ~\$140 million (one fifth of \$700 million) is evenly incurred every year from 2010 to 2014.

The cost of ~\$140 million assumed incurred in the middle of 2010 is valued to be ~\$183 million on 1 January 2015 by applying the discount factor $1/(1+0.05)^{(2015-2010+0.5)}$ at the 5% real discount rate also taken from Table 4. Similarly, the costs incurred in the middle of 2011, 2012, 2013 and 2014 discounted to 1 January 2015 are valued, respectively, at \$174 million, \$166 million, \$158 million and \$151 million, which, added to the \$183 million of 2010, result in a total refurbishment cost accumulated over the five years and discounted to 1 January 2015 of \$832 million.

Now that the total refurbishment cost valued on 1 January 2015 has been calculated, the total LTO cost, inclusive of refurbishments/upgrades and operational costs, can be assessed.

5.3.3. Total cost of long term operation

As shown in Table 5, the discounted total cost, excluding the contribution for decommissioning, is calculated to be ~$2533 million, discounted at the rate of 5% to 1 January 2015.

The components of the total cost include the refurbishment investment, the cost of O&M, the fuel cost and any contributions to the local communities. The table displays the total cost and the breakdown by cost item for the full period. The unit used in the table is one million dollars.

5.3.4. Contribution of decommissioning to long term operation

Decommissioning is a cost that is incurred in the future, when the NPP ceases operation. In accounting, the decommissioning cost is allocated to expense by being depreciated over the design life of the plant. From an accounting perspective, the amount required for decommissioning depends on how much the decommissioning fund has depreciated over the design life of the plant.

Using the example in Table 4, in order to calculate the total cost attributable purely to LTO, the cost saving due to the ten year delay of decommissioning must be taken into account. Assuming that the decommissioning cost has been completely paid off during the original design life of the NPP, there will be no contributions to the decommissioning fund during the LTO period. The fund will continue to accrue interest. This amount can be considered a cost saving for LTO.

To evaluate the contribution of decommissioning to LTO, two decommissioning scenarios are envisaged:

TABLE 5. TOTAL COST OF LONG TERM OPERATION, EXCLUDING DECOMMISSIONING ($ million)

Year	Overnight refurbishment cost of LTO	O&M	Fuel	Spent fuel disposal	Payment for regional society	Total cost, excluding decomm.	Discount factor	Discounted total cost, excluding decomm.
2014	700					832.00	1.188571	832.00
2015		123.17	69.53	23.14	2	217.84	0.9759	212.59
2016		123.17	69.53	23.14	2	217.84	0.929429	202.47
2017		123.17	69.53	23.14	2	217.84	0.88517	192.83
2018		123.17	69.53	23.14	2	217.84	0.843019	183.65
2019		123.17	69.53	23.14	2	217.84	0.802875	174.90
2020		123.17	69.53	23.14	2	217.84	0.764643	166.57
2021		123.17	69.53	23.14	2	217.84	0.728232	158.64
2022		123.17	69.53	23.14	2	217.84	0.693554	151.09
2023		123.17	69.53	23.14	2	217.84	0.660528	143.89
2024		123.17	69.53	23.14	2	213.00	0.629074	133.99
Total								2533.00

— Shutdown and decommissioning as foreseen in the original licence without LTO (scenario 1).
— Decommissioning postponed (LTO case). The cost amount and the timing of decommissioning change (i.e. additional waste produced, interest accrued, etc.) (scenario 2).

For scenario 1, the categories that make up the total decommissioning cost are:

— *NPP decommissioning/dismantling.* This is the main cost of decommissioning. It reflects the costs of decontamination; segmentation of the NPP main components, including the reactor vessel; of removal, transportation and storage of the parts; of the demolition of the reactor building and other buildings; and of the site restoration to green field conditions (if feasible).
— *Spent fuel disposal.* This is an associated cost assumed to include the construction costs of the spent fuel repository buildings (and/or the deep geological repository for high level waste).
— *Spent fuel transportation and dry storage*. This is assumed to reflect the costs of construction of the dry storage facility (if required), of the procurement of containers, and of spent fuel transportation from the pit to the dry storage facility at the site [20].

The last two subsidiary costs associated with decommissioning an NPP should be contributed to a decommissioning fund throughout the NPP's operating life to cover all decommissioning and waste management costs.

From Table 4, the decommissioning cost is assumed to be 15% of the overnight construction cost, namely \$4319/kW, and the installed capacity is shown as 1343 MW(e). Decommissioning would start six years after the last day of operation (for scenarios 1 and 2) to allow enough radioactive decay of primary side components before decontamination operations begin. With these numbers the decommissioning cost is calculated as follows:

Decommissioning cost = [15% × \$4319/kW × 1343 MW × (1000 kW/MW)] × [10] ^ (-6) = \$870 million

The discount rate in this example equals the interest rate, and is expressed in nominal value. For scenario 1, without LTO, the decommissioning would take place in 2020, six years from the last year of operation. The decommissioning cost discounted to 1 January 2015 is valued at \$665 million by applying the discounting factor $1/(1 + 0.05)^{(2020-2015 + 0.5)}$ to the decommissioning cost of \$870 million.

For scenario 2, which includes LTO, NPP decommissioning is delayed to 2030. The decommissioning cost discounted to 1 January 2015 is reduced to \$408 million by applying the discounting factor $1/(1 + 0.05)^{(2030-2015 + 0.5)}$.

The difference between the two values, \$665 million – \$408 million = \$257 million, is the cost savings due to the ten year delay brought about by LTO, which can also be equated to accrued interest on the decommissioning savings fund.

Decommissioning is priced differently in different countries. In the Republic of Korea, for example, the electricity act specifies that decommissioning an NPP should occur five years after the end of its service life. The cost of decommissioning for a standard plant in the Republic of Korea was calculated to be 603.3 billion won (about \$550 million) and assumed to be constant up to the end of 2012. The decommissioning cost should be interpreted as being similar to an overnight cost because time is not a factor.

The amount disbursed for decommissioning is:

$$\frac{\text{Initial provision} = \text{Estimated cost x}\left(1+\text{escalation rate}\right)^{\text{escalation period}}}{\left(1+\text{discount rate}\right)^{\text{discount period}}} \tag{1}$$

Escalation and discount rates are reported as 2.93% and 4.49%, respectively. These parameters are revised every five years.

If we assume D is the decommissioning cost, f the escalation rate, r the discount rate and p the period from first commercial operation to decommissioning, according to Eq. (1), the initial provision at the start of commercial operation is $D(1 + f)^p/(1 + r)^p$. For consecutive years, only the compound interest on the total provisions accumulated at that time is added to the initial provisions. The annual provisions are calculated using Eq. (2):

Annual provisions = initial provision × discount rate (1 + discount rate)$^{n-1}$ (2)

The total amount in the fund provided for decommissioning is represented Eq. (3):

$$\text{Total provisions for decommissioning} = D(1+f)^{p} \tag{3}$$

Equation (3) indicates that the total amount of provisions for decommissioning is affected not by the discount rate (r) but by a parameter comprising the decommissioning cost (D), the escalation rate (f), and the decommissioning period (p). The discount rate has an impact only on the amount scheduled to be accumulated at the end of the operating period.

In the Republic of Korea, the amount of money required for decommissioning one nuclear power unit is deposited into a decommissioning trust fund. It is worth noting that when annual provisions are costs without cash payments, there is a major difference between the financial and the economic analysis. When the money equivalent to the annual provisions is set aside and deposited into a decommissioning trust fund, it earns a rate of return over the lifetime of the plant, and keeps growing until decommissioning is complete. LTO contributes to savings because it delays the time of decommissioning, resulting in a further increase in the time value of the money deposited.

5.3.5. Total revenues from long term operation

The main benefit from LTO is the revenue from selling electricity generated by the plant. As revenue equals the electricity price times the amount of electricity generated by the plant, the yearly revenue is calculated as follows:

— The electricity price is assumed to be \$40/MW·h (from Table 4).
— The amount of electricity generated per year is 9 932 964 MW·h, which comes from 1343 (MW) × 8760 (hours/year) × 0.85, where 0.85 is the average capacity factor of the plant.
— The annual revenue is \$40/MW·h ×9 932 964 MW·h equals ~\$397 million.

TABLE 6. YEARLY REVENUE FOR THE FULL LTO PERIOD

Year	Electricity generation (MW·h)	Electricity price (\$/MW·h)	Revenue (\$ million)	Discount factor	Discounted revenue (\$ million)	Discounted electricity generation (MW·h)
2015	9 932 964	40	397	0.97590	387	9 693 580
2016	9 932 964	40	397	0.929429	369	9 231 985
2017	9 932 964	40	397	0.885170	351	8 792 362
2018	9 932 964	40	397	0.843019	335	8 373 677
2019	9 932 964	40	397	0.802875	319	7 974 928
2020	9 932 964	40	397	0.764643	304	7 595 171
2021	9 932 964	40	397	0.728232	289	7 233 502
2022	9 932 964	40	397	0.693554	275	6 889 047
2023	9 932 964	40	397	0.660528	262	6 561 001
2024	9 932 964	40	397	0.629074	250	6 248 569
Total					3 141	78 593 823

The yearly revenue needs to be discounted to 1 January 2015 the same way costs were discounted. Table 6 shows the yearly revenue for the full period.

The last column in Table 6 shows discounted electricity generation for calculating LCOE used to compare the economics of power options.

LCOE is obtained by dividing the discounted total real cost of LTO from Table 5 (2533×10^6) by the discounted total electricity generation from Table 6 (78 593 823), which gives LCOE = \$32/kW·h. This number can be compared to the LCOEs of alternative power options in the electric supply system.

NPV is the difference between the present value of the total discounted revenue from Table 6 (\$3141 million) and the total real cost of LTO (\$2533 million), which gives \$624 million. As the NPV of the LTO exceeds zero, excluding the effect of risks and uncertainties, it could be concluded that there are no major obstacles for LTO.

5.3.6. Uncertainties and risks in economic evaluations

The examples shown so far were based on the median value of the projected cost of generating electricity without risk considerations [37]. However, the economic parameters affecting the viability of an LTO project are subject to uncertainties. For this reason, risk management concepts are applied to key input parameters, particularly electricity pricing, capacity factors, investment costs, decommissioning costs, discount rate and carbon dioxide pricing policies (if applicable). Risk and sensitivity analyses are conducted using tools such as Monte Carlo simulations in the economic assessment of LTO and of its alternatives.

5.3.6.1. Electricity price uncertainties

Electricity prices are heavily influenced by economic regulations (rate setting or liberalization of the electricity market). No economic regulatory policy exists specifically for nuclear plant ageing, life management or LTO. The difference between a regulated and a liberalized electricity market is the establishment of a competitive electricity generation marketplace via spot markets, day-ahead auctions and over the counter trading activity.

In a liberalized market, the prices of electricity are volatile; power plants are not guaranteed a fixed return on capital investments or the ability to pass on increases in fuel prices to customers directly. Therefore, owners of power generators have had to modify their capital allocation and marketing strategies to resemble more closely those typical of a competitive market, balancing expected returns with portfolio risks. There are two components to price uncertainty, a short-run volatility element, which is expected to oscillate around some mean value, and a long run uncertainty element about the value of this mean. Only the long run uncertainty component needs to be considered, since short term oscillations around the mean will not affect investment conditions.

A comparison of the average electricity prices in Europe in the past ten years and of the projected costs of electricity generation at new NPPs shows that there is an investment risk for owners/operators. This risk element favours LTO because of the smaller investments needed if compared to new builds.

The uncertainty of future electricity prices caused disagreements among the analysts on how the electricity demand responds to electricity prices. This uncertainty constitutes a large risk item in the economic analysis of the power generation options.

5.3.6.2. Carbon dioxide pricing policy uncertainties

One important element of uncertainty that may weigh on electricity prices is carbon dioxide and, in general, carbon pricing policies adopted in a number of Member States. Energy and climate policies, with feed-in tariffs for renewal energy or green certificate systems, such as the European emission trading system for carbon dioxide, may influence the feasibility of an LTO investment.

Carbon dioxide price uncertainties are driven by three possible market postures:

— Price fluctuation in the short term;
— Price drifting in the long term;
— Price jumping caused by sudden changes in emission mitigation policies.

The nature and requirements imposed by carbon mitigation policies are still being fine-tuned in real situations, and, in some cases, they have even been reversed because of unpredicted negative side effects. Their impact on power generation projects remains highly uncertain. Even if a policy approach is established, policy uncertainty can still be significant. In fact, as a pre-eminent example, carbon prices in Europe have varied greatly from the beginning of the carbon mitigation policies in 2008, when the second phase of the cap and trade market policy started. In addition, carbon mitigation technologies, such as carbon capture and storage, are in the development phase and uncertainty exists regarding their cost efficiency.

Carbon policy uncertainty affects the power generation market in proportion to the level of investment. At the producer level, carbon policy uncertainty creates path dependency in asset acquisition, with the result that new investment decisions depend on the existing power generation assets and on how they interact with the carbon cost policy risk. Carbon policy uncertainty translates into uncertainty regarding which power technology to select and the planning period. As is typical in practice, such investment models are driven by discounted cash flow based valuations.

At the market level, carbon policy uncertainty translates into incentives to invest in excess capacity in both fossil and renewable technologies. Given the uncertainty of the electricity demand, having excess capacity can be beneficial to both consumers and power generating plant owners.

In theory, increasing concerns about carbon dioxide emissions, added to the need for electricity in bulk with continuity of supply, should have implied stronger prospects for nuclear power generation. Current carbon dioxide allowances on power exchanges are low, but uncertainties on future carbon dioxide emission prices weigh on cost risks in LTO economic analyses.

5.3.6.3. Discount rate and investment cost uncertainties

One key determinant of any asset valuation approach is the discount rate at which future cash flows are discounted. When comparing discount rates, it is important to distinguish between discount rates resulting from the assumptions used on project risk and those resulting from different financing assumptions.

To estimate the discount rate for a project, assuming it is 100% equity financed, the most common practice is to add project specific risk premiums to the risk free rate of return. The risk free rate of return is generally assumed to equal long term rates of return to government bonds over long periods. The estimation of risk premium is complex. If the risk of the project in question is similar to previous projects and if the company's stocks are traded on the open market, then in principle the risk premium can be estimated using published historical stock price data.

Research showed that between 1970 and 1984, independent of financing issues, the discount rate for a typical utility investment project would have been about 5% (the 3% real risk free rate plus the 2% risk premium). This was in fact lower than the discount rate for typical investments and reflected the fact that costs could in general be passed on to consumers and that a large proportion of the investments were in relatively low risk projects such as transmission and distribution.

In the more open electricity market, cost recovery is not guaranteed, and building and operating any power plant is risky. The US Energy Information Administration suggests using a discount rate based on the stock prices of two industries, airlines and telecommunication, whose "structure and size are an appropriate guide to the current and future utility industries". Independent of financial issues, the discount rate used by the US Energy Information Administration for evaluating utility investment is about 10% in real terms (the 3% risk free return plus a 7% risk premium).

The various generation technologies present different risks and have been affected differently by the new risks introduced by the liberalization of the electricity industry [38, 39]. Consequently, some recent studies use different discount rates for different technologies. These discount rates reflect different assumptions about how they can be financed. Technologies seen as financially risky may require a higher return on investment.

Technology specific discount rates vary by country and by circumstances with regard to the perceived risk of investment in different options and the cost of financing among other factors. Countries where perceived risks in nuclear power are lower might have a much smaller gap in the weighted cost of capital between the options. Costs of capital vary from case to case. However, access to cheaper capital does not reduce risks, but merely transfers these risks to others (e.g. to the state or to the power consumers).

An innovative and relatively controversial approach to discount rates is to use different market based discount rates for the costs and revenues of a power generation project. The idea is to discount the costs and revenues of a project at different rates according to their riskiness.

In the case of nuclear power generation, the LCOE is largely dominated by fixed costs, especially for large discount rates. O&M costs are also significant, and the share of the fuel costs is considerably smaller for nuclear than for other thermal plants.

The discount rate is possibly one of the most critical parameters of this type of analysis. Given the large weight of investment costs for nuclear, the rate at which these costs are written off will largely determine the competitiveness of this technology. The most relevant question is whether the discount rate for nuclear has to be different from that for gas or coal. Here, a reasonable WACC measure can be used as the 'hurdle rate'. For example, a WACC of 9% can be used as a baseline assumption with a range between 3 and 12%.

The investment costs represent the yearly amount relating to the repayment of the principal debt and the sum of the investment expected to be made in the year, including the purchase of small assets. The uncertainty regarding the investment cost comes from the fact that there may be increasing marginal costs to investment, and these may vary over time. In addition, there can be no certainty that investment costs will not be sensitive to increased uncertainty in future electricity output prices and to uncertainty in future discount rates.

5.3.7. Monte Carlo simulation: Treatment of uncertainties in economic assessments

As discussed in Section 4, Monte Carlo simulations are an efficient way to take into account uncertainties in economic evaluations. In performing these simulations, a statistical distribution is provided for each input parameter. Each distribution provides random samples, representing the values of the input parameters. With uniform distributions, all that is needed is the maximum and minimum values for the input parameters. The input parameters for which a uniform distribution is given are electricity price, capacity factor, O&M cost, spent fuel removal, disposal and storage, decommissioning cost and refurbishment cost.

A sample of minimum and maximum values assigned for each parameter is given in Table 7.

Except for the electricity price, minimum and maximum values for each input parameter are set to be more severe than the value taken from Ref. [37] to reflect the ageing effect of the plant. All the cost input parameters are set to range from the reference value to 30% higher. The Monte Carlo based software can be set to calculate the NPV ranges. The NPV range for cost input parameters is shown separately and simultaneously, together with the standard deviations. The number of samples drawn from each distribution in the Monte Carlo simulation is 10 000. The simulation is performed independently for each cost input parameter to show its effect on the NPV. As shown in Table 8, the effect of each parameter on the NPV is ranked in the following order: O&M cost; refurbishment cost; decommissioning cost; and spent fuel removal, disposal and storage cost. O&M cost has the greatest effect on NPV among the selected cost input parameters, while the effect from spent fuel removal, disposal and storage has the smallest. The effects of refurbishment and decommissioning costs lie between the two extremes.

When the cost input parameters are simultaneously applied in Monte Carlo simulations, the range of NPVs is 218~801, the mean value is 509 and the standard deviation is 109. This means that the effect on NPV of the cost input parameters becomes greater when they are considered simultaneously. The Monte Carlo simulation results for electricity price and capacity factors are shown in Table 9.

Table 9 shows that the effect on NVP is greater from the electricity price and the capacity factor than from the cost input parameters.

Considering all the input parameters simultaneously in Monte Carlo simulations, the distribution of NPV is shown in Fig. 6. When the uncertainties increase to certain values, negative NPVs occur in the simulation.

Figure 7 shows that NPV ranges between \$498 and \$1438 million, the mean value is +339 and the standard deviation is 389 (115%). The probability of negative NPVs is about 22% from this simulation. A number of Monte Carlo simulations, whose results are shown in Figs 7–10, were performed to see the effects of the discount rate on NPVs. Discount rates of 3%, 5%, 7% and 10% were selected.

Table 10 shows that the higher discount rates have a greater probability of producing negative NPVs. As expected, discount rates are lower for nuclear power operators in regulated electricity markets than in liberalized markets. The results support the general observation that the market structure in which an NPP operates makes a significant difference to the economic viability of LTO.

TABLE 7. MONTE CARLO SIMULATION: MINIMUM AND MAXIMUM INPUT PARAMETERS

Parameter	Reference value	Minimum value	Maximum value
Electricity price ($/MW·h)	40	30	50
Capacity factor (%)	85	60	85
O&M cost ($/MW·h)	13.33	13.33	17.33 (=13.33 × 1.30)
Spent fuel removal, disposal and storage ($/MW·h)	2.33	2.33	3.03 (=2.33 × 1.30)
Ratio of decommissioning to overnight construction cost (%)	15	15	20
Refurbishment investment (million $)	650	650	845 (=650 × 1.30)

TABLE 8. MONTE CARLO SIMULATION: NPV FOR EACH COST INPUT PARAMETER

Cost input parameter	Range of NPV	Mean	Standard deviation
O&M cost	461~755	610	85 (14%)
Refurbishment cost	535~755	645	63 (9.8%)
Decommissioning cost	755~832	794	22 (2.8%)
Spent fuel removal, disposal and storage	704~755	730	15 (2.1%)

TABLE 9. MONTE CARLO SIMULATION: EFFECT OF COST INPUT PARAMETERS ON NPV

Cost input parameter	Range of NPV	Mean	Standard deviation
Electricity price	19~1492	757	428 (56.5%)
Capacity factor	380~755	567	108 (19.0%)

TABLE 10. MONTE CARLO SIMULATIONS OF NPVs AT VARIOUS DISCOUNT RATES

Discount rate in real terms	3%	5%	7%	10%
Mean NPV ($ million)	411	339	264	130
Standard deviation of NPV ($ million)	423 (103%)	389 (115%)	355 (134%)	320 (246%)
Range of NPV ($ million)	-500~1587	-498~1438	-519~1246	-624~1042
Probability of negative NPV	20%	22%	28%	38%

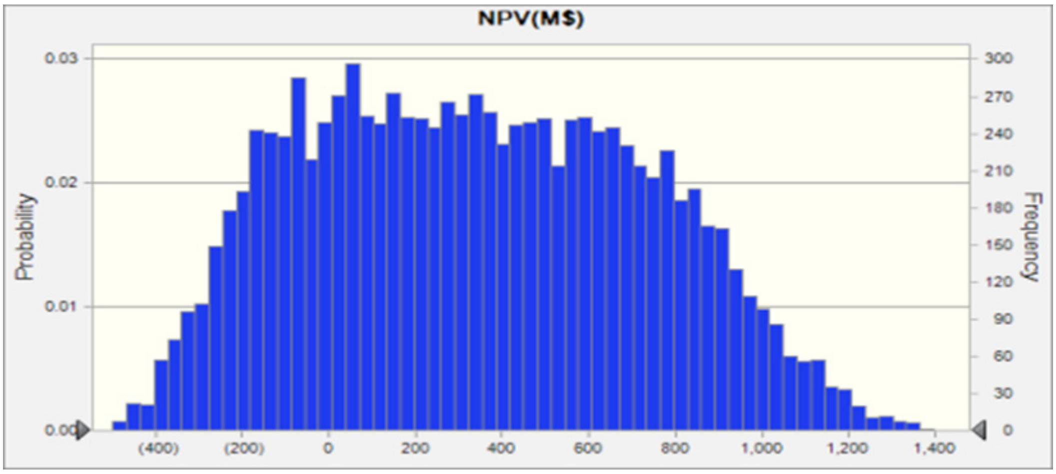


FIG. 6. Monte Carlo simulation results for NPVs with all input parameters.

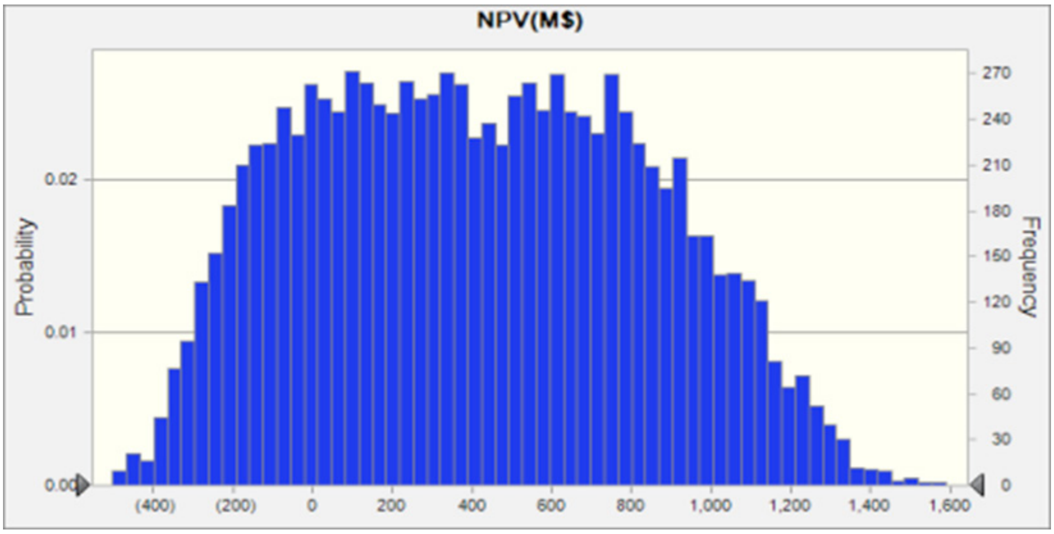


FIG. 7. Monte Carlo simulation of NPVs at 3% discount rate.

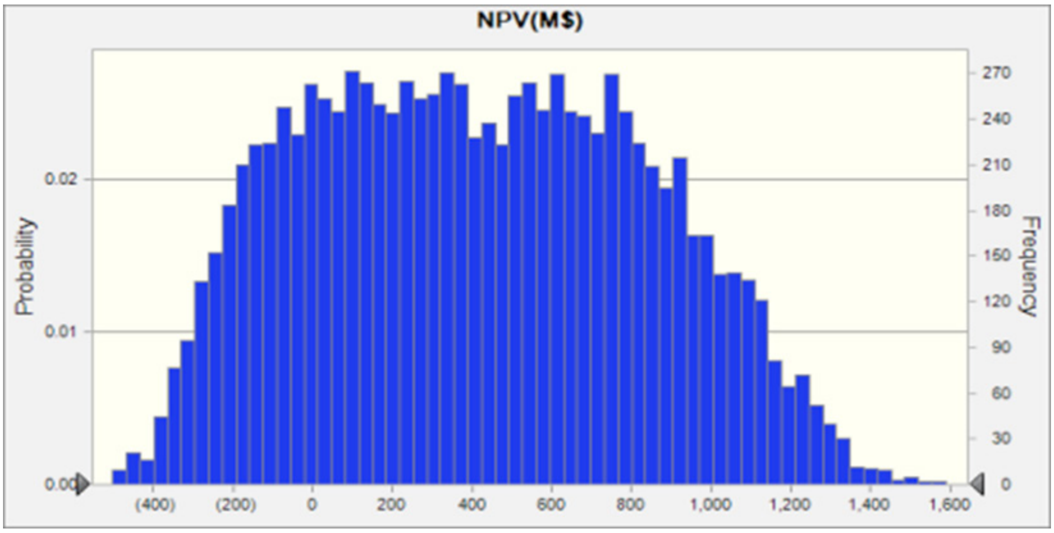


FIG. 8. Monte Carlo simulation of NPVs at 5% discount rate.

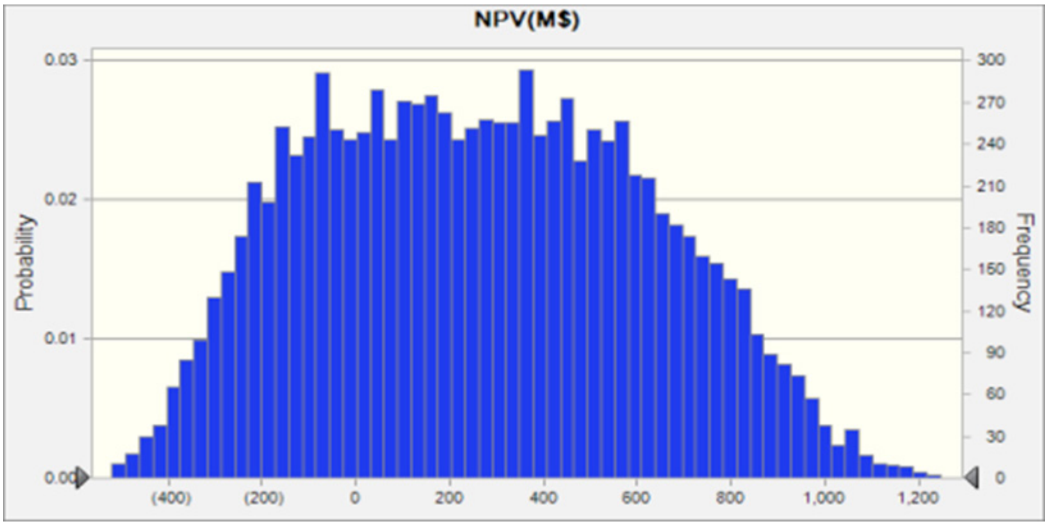


FIG. 9. Monte Carlo simulation of NPVs at 7% discount rate.

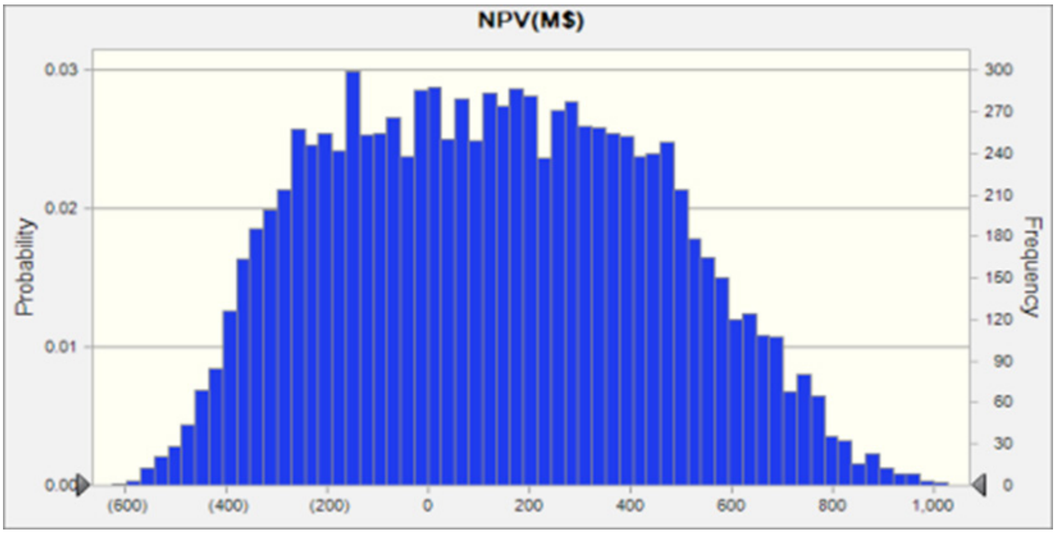


FIG. 10. Monte Carlo simulation of NPVs at 10% discount rate.

Any decision on whether to pursue LTO should include externalities in the economic assessment of all options. The difference to the electrical system cost due to externalities is more apparent, when diversifying the power mix. As nuclear power usually provides baseload electricity, LTO may change the mix of baseload power generators, such as coal and nuclear power operating simultaneously. If there is a cost difference between the power produced by the NPP during LTO and the power produced by the other option, the cost difference should be shown as a cost saving. The total cost revised to reflect externalities due to the LTO option could be used for calculating the NPV. Typical positive externalities from LTO include electricity price stabilization and carbon emission reductions.

Tools for planning electrical system expansion, such as MESSAGE and WASP[8], can be used to show the cost effects of LTO on the system. This allows a comparison of electrical system costs with and without LTO. The cost difference could then be considered in calculating the NPV. As the electrical system costs are a major component of the electricity price, a fall in electricity prices brings about positive externalities on the national economy. When LTO contributes to the stabilization of the electricity price, the contribution needs to be estimated

[8] IAEA energy models:
MESSAGE: Model for Energy Supply Strategy Alternatives and their General Environmental Impacts;
WASP: Wien Automatic System Planning Package.

and added to the benefit side in the economic assessment of extended operation. The value from mitigating GHG emissions with the LTO option should be added to its benefits list. Various approaches could be used to quantify the economic contribution. Sometimes it is convenient to use LCOE to compare economics between LTO and alternative power options. In comparing these LCOEs, the decommissioning cost difference with and without LTO should be considered.

5.3.8. Overview of LTOFIN

LTOFIN was developed to assist in performing an LTO economic assessment within the framework of the process described above.

The model can be used for evaluating the financial viability of LTO for a single nuclear unit or for a group of units, up to a maximum of ten. In all cases, the nuclear unit or the group of units would be considered one profit centre. A larger number of units, or more than one group of nuclear units, could be handled through multiple runs of LTOFIN.

LTOFIN is based on the IAEA's model FINPLAN[9] and uses Microsoft Excel as a platform. It consists of a set of worksheets with a front end for user inputs, a computational part and an output module for viewing and analysing results. Figure 11 shows the LTOFIN scheme.

The input module provides a user friendly and convenient method to input the data. In this module, the user can define all the technical and economic data, as well as all the assumptions made for the scenario being considered. The output module contains the results of the analysis and provides reports on the financial performance of the proposed LTO period. This module enables users and management to view and print a number of standard, pre-formatted graphical and tabular output reports for different scenarios.

The LTOFIN computation module performs all necessary calculations on a yearly basis, such as those for sales, costs, depreciation, tax, decommissioning fund, cash flow, dividend payments and financial performance ratios.

It also produces standard financial statements, such as balance sheets, operating accounts and income statements. Figure 12 shows the input module of LTOFIN assumption.

Under competitive electricity market conditions, a decision in favour of LTO of an NPP requires a complex evaluation of not only the production cost and other economic indicators, but also the business viability of the LTO investment proposal. Financial analysis thus becomes the most important factor in decision making. In some cases, the financial analysis of an LTO proposal can lead to a different conclusion than that based on economic assessment, because financial analysis is performed in nominal monetary values, i.e. currency of the year spent or

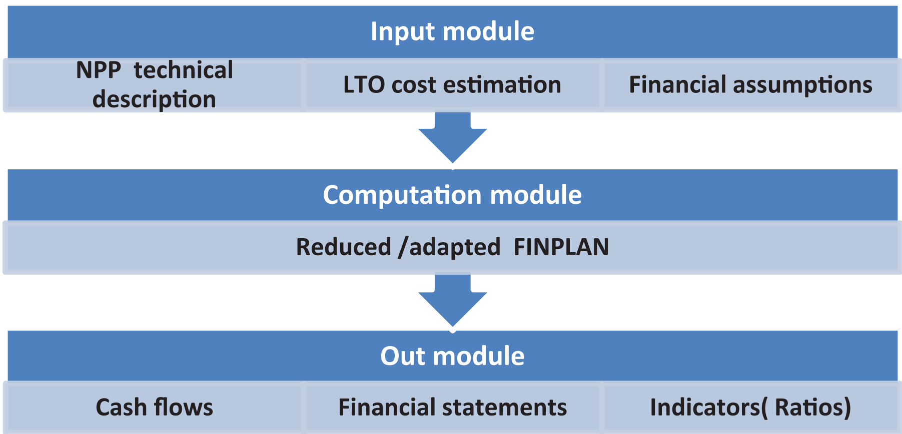


FIG. 11. Scheme of LTOFIN.

[9] The FINPLAN model (Model for Financial Analysis of Electric Sector Expansion Plans) has been developed to carry out a financial analysis of a power project or an expansion programme to determine whether the project or the programme is viable for the utility and the country involved. It assesses the feasibility of electricity generation projects by computing important financial indicators while taking into account financing sources, costs, revenues, taxes, etc. It is particularly helpful for establishing the long term financial viability of projects by preparing cash flows, income statements, balance sheets and financial ratios.

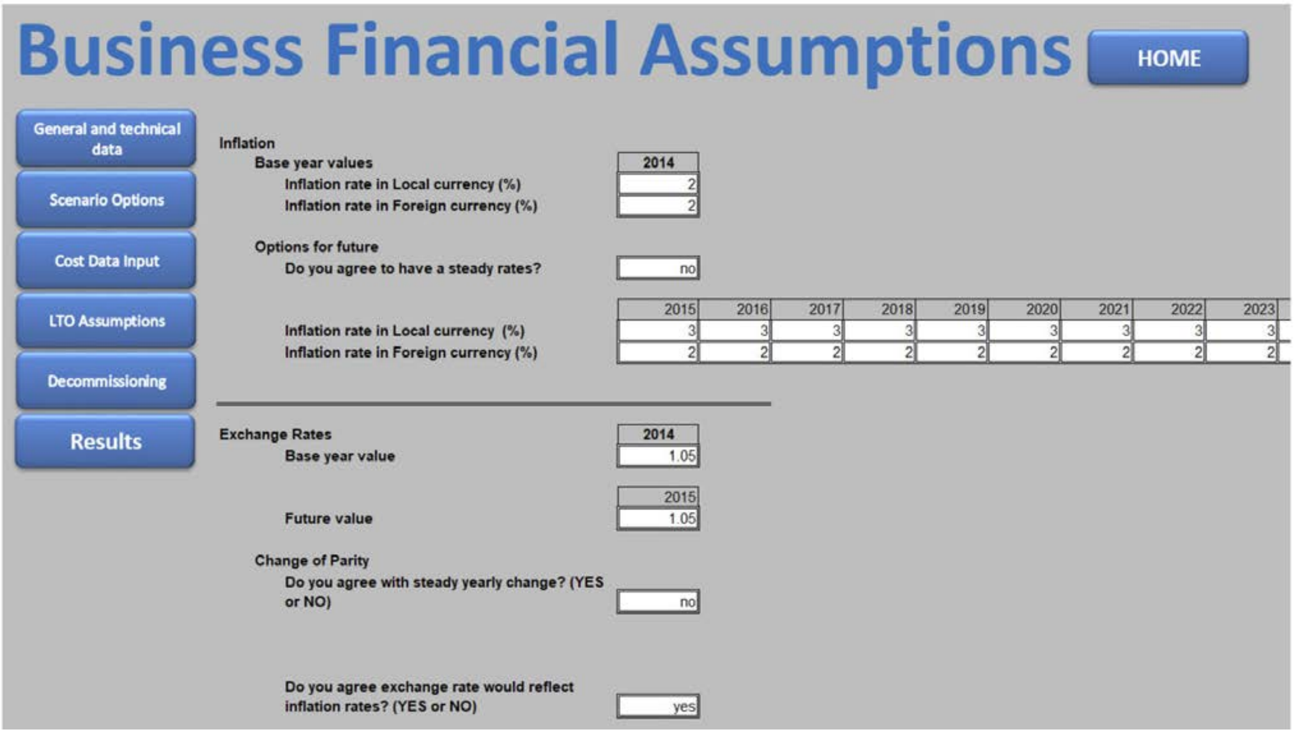


FIG. 12. Screenshot of the LTOFIN assumptions input module (text uncorrected).

earned, and not in constant monetary values as is the case with an economic assessment. Additionally, inflation and escalation are included in all costs as well as in prices. Finally, all taxes/subsidies are accounted for. The possibility of financing the investment from long term and short term loans, a company's internal sources, equity and other sources is considered. The cash flows with schedule are properly recorded. Using all these details, the LTOFIN prepares estimates of a company's financial statements and shareholders' accounts for the future years of operation.

To demonstrate financial analysis with LTOFIN, it is assumed that the 1343 MW NPP is owned by a company which operates the plant and sells electricity at the market price of \$40/MW·h. The total investment of \$700 million required for ten year LTO of the NPP is assumed to be financed by a 70:30 debt equity arrangement. It is further assumed that general inflation is 2% and the company must pay a corporate tax at a rate of 20% of the profits. The income statement estimated by LTOFIN is presented in Figs 13 and 14.

It should be noted that the estimated revenues are marginally higher than the expenses in all the years and, consequently, the profits are meagre, giving only a 0.6% return to shareholders. If the price of electricity increases in the future, the profit could be higher but for a realistic return on shareholders' equity — around 7% — the electricity price has to be above \$50/MW·h.

This analysis shows that although the LTO proposal appears to be attractive based on an economic assessment — the levelized cost of generation of \$32/MW·h compared with an electricity price of \$40/MW·h — it is not viable from the financial viewpoint under the given set of assumptions. Detailed sensitivity analysis can be conducted to identify the critical assumption influencing the financial viability of the LTO proposal. Additionally, business risks can also be assessed using Monte Carlo simulations or scenario analysis.

Further information on the structure of the feasibility report, of which the techno-economic assessment is a part, can be found in Appendix III.

FIG. 13. Screenshot of LTOFIN calculation results.

Income statements ($ million)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Fixed revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total sales	389.40	402.28	415.60	429.35	443.56	458.23	0.00	0.00	534.96	552.67
Foreign exchange gain	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interest earnings	1.00	1.90	2.71	3.44	4.10	4.69	5.22	2.66	0.00	1.73
TOTAL REVENUES	**390.40**	**404.18**	**418.31**	**432.79**	**447.65**	**462.92**	**5.22**	**2.66**	**534.96**	**554.40**
General expenses	10.61	10.93	11.26	11.59	11.94	12.30	12.67	13.05	13.44	13.84
Purchase from IPP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Local fuel cost	123.76	128.11	132.62	137.28	142.10	147.10	0.00	0.00	163.16	168.90
Foreign fuel cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Local O&M cost	113.32	117.22	121.24	125.41	129.72	134.18	76.50	79.08	148.49	153.60
Foreign exchange loss	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Depreciation	90.00	81.00	72.90	65.61	59.05	53.14	47.83	43.05	117.49	113.62
Total expenses	**355.97**	**358.88**	**362.81**	**367.69**	**373.49**	**380.14**	**136.99**	**143.90**	**486.71**	**494.17**
Profit/loss	**34.43**	**45.30**	**55.50**	**65.09**	**74.16**	**82.77**	**-131.78**	**-141.24**	**48.25**	**60.23**

FIG. 14. Income statements for a projected ten year long term operation case.

6. EFFICIENT IMPLEMENTATION OF A LONG TERM OPERATION PROJECT

6.1. PLANNING FOR THE PRESERVATION OF HUMAN RESOURCES

The decision to undertake an LTO project is undoubtedly a major challenge, especially if it is the first experience of this kind for the owner/operator. It will also be a challenge for the other parties involved, such as staff, regulators, government authorities, local and foreign contractors and the general public. Near the end of a plant's design life, the risk of losing human resources increases, particularly if there is a lack of clarity about future plans, LTO, relicensing, and the like, and decisions are postponed or communicated too late. The staff may lose motivation and leave. The problem becomes particularly acute if core staff and lead figures in the organization begin to leave. It should not come as a surprise that adequate human resources in terms of quality and numbers are key elements for the successful implementation of an LTO project.

In order to manage attrition and preserve skills plant management should implement a few crucial initiatives. At a minimum, the owner/operator should establish a core group of dedicated, essential, first line managers and senior technical personnel to carry out and manage transition activities, exercise leadership and provide continuity. The roles and responsibilities of the core group must be well defined and organized. The owner/operator should ensure that the core group has the right set of skills necessary to preserve continuity and protect corporate memory and corporate culture throughout the LTO period. The owner/operator should apply adequate methods to preserve the strengths of the technical core group, maintain the right level of activities and programmes aimed at developing and preserving core skills, and attract and motivate younger personnel to maintain the vitality of the core group.

The project management organization for an LTO project may be staffed through promotions from the ranks of the core group and/or through new hiring, where necessary. Among the many key responsibilities of the core group, the following should not be underestimated:

— Maintaining an accurate and up to date record of the plant state (configuration management);
— Being aware of evolving regulatory developments and trends;
— Keeping up to date on technical and quality standards, on operational experience feedback and on technical developments (technology watch function);
— Periodically assessing the plant condition against developing requirements;
— Identifying all necessary modifications, as well as the time and resources required for their implementation.

While preparing the human resource plan for the LTO period, the following factors must be taken into consideration:

— *Cost and availability of resources.* These are key elements in deciding the measures to be taken in order to retain qualified personnel. Reducing staff to save money during the refurbishment outage will inevitably result in a longer time to assemble appropriate personnel and retrain them for restart. This will itself generate delays and costs.
— *Skills required.* The risk of losing staff with multidisciplinary technical and managerial skills in different fields acquired through training and experience should be prevented, or at least minimized. The need for qualified personnel to implement the LTO upgrades should not be neglected. Once lost, these skills cannot be quickly reacquired. Therefore, incentives should be budgeted to preserve the corporate skill levels. In addition to the core technical skills, specific skills will be required for the negotiation of contractual arrangements between the owner/operator and the various contractors. At the time of plant restart, after a long LTO outage, it is always necessary to carry out commissioning tasks such as tests and preparation of the newly installed SSCs and of the entire configuration in order to demonstrate performance and adequacy. This cannot be done if skilled staff are let go.
— *Extensions of the LTO outage duration.* If the outage period is extended, because of regulatory or other technical, supply or administrative reasons, the HR management plan may have to be modified. If the delay is long and the plant restart date is difficult to predict, then the HR action plan must be flexible, and periodical revisions become necessary. Delays in the duration of the LTO outage may best be managed by slowing down

construction, rather than by enforcing a complete stoppage until all obstacles are removed. This will result in more effective staff utilization and facilitate the retention of key personnel.

— *HR strength.* In order to retain and develop human resources within budgets and other constraints, plant management must consider and implement activities in parallel that will keep all staff engaged in the plant upgrade work, ensure the schedule is respected and the critical path is given top priority at all times. Supervisors should set an example and counter the tendency to disregard the schedule and constantly show their commitment to staff motivation and concrete initiatives to meeting targets.

The LTO implementation plan should avoid any kind of work discontinuities. Activities such as design, procurement, implementation of modifications and outstanding work orders and quality assurance should be undertaken in such a way that the continuity of the project/plan is safely maintained. Encroachment of activities should be carefully avoided. Activity control, such as work monitoring and budget control, should be pursued vigorously and periodical reports made available to senior management.

During long outage periods, the work force may be temporarily redeployed with a view to retaining and enhancing their skills. Younger staff need to be given increasing responsibilities, with senior staff serving as mentors. This provides younger staff with highly effective on the job training and prepares them to replace retiring staff.

During long LTO outages, salaries need to be maintained at a level equal to or exceeding alternative opportunities; satisfactory social and cultural conditions should be maintained for employees and their families to minimize attrition and prevent a possible exodus.

6.2. TENDER DOCUMENT PREPARATION FOR A LONG TERM OPERATION PROJECT

Before financial disbursement for an LTO project, certain conditions should be met. The pre-project phase is a delicate period with its uncertainties. In addition to economic and technical challenges, risks of a political, social and environmental nature may cause disruptions. Political and social support may be withdrawn at any stage because of unanticipated situations, such as changes in government policies, financial crises or conflicts. Therefore, government guarantees and investment protection measures may be required before proceeding with any concrete financial commitments, and therefore with invitations to bid on a project [39].

6.2.1. Pre-qualification of bidders/suppliers

To ensure that prospective suppliers have the necessary competence and experience to successfully complete a contract, they should be required to submit to a pre-qualification process. The process should include a demonstration of the vendor’s technical competence, qualifications in terms of the applicable codes and standards, quality assurance requirements, financial capability and availability of skills and resources, all supported by suitable references from the supplier’s country and internationally. Pre-qualification is an excellent method of pre-screening bidders. For this purpose, a questionnaire to acquire the required data should be developed and sent to potential vendors. An effective and comprehensive quality assurance programme should be an essential precondition for qualifying bidders. The quality assurance and quality audit programmes of potential bidders should be reviewed. Only after the pre-qualification of bidders is complete and the bidders list is issued can the bid invitation specification (BIS)/tender documents and a request for participation in the bidding process be distributed to the qualified bidder.

When the necessary protective measures are in place, the owner/operator prepares the tender document and issues the BIS to qualified vendors. In order to understand the process, it is essential to familiarize oneself with the pre-conditions needed to support the BIS. Before the invitation to bid is issued, there should be a bidder pre-qualification process in which the interested bidders are examined in terms of their financial, legal, regulatory and technical capabilities, as well their compliance with training, radiation protection and interface requirements. The owner/operator should review the various bid invitation options and the types of contracts available and select the most appropriate contract for the specific conditions of the NPP. At the back end, the outcome of the entire process also needs to be understood, namely the reception of the quotations (bids) from the contractors in response to the BIS, the owner's technical and commercial evaluation, the selection of the winning bid, the contract negotiations, and so on.

6.2.2. Tender document/bid invitation specification

Writing a BIS document requires a great deal of knowledge and experience in all the relevant fields. The original vendor or the original architect–engineering firm most familiar with the design requirements of the plant should be contacted for assistance. The original vendor may provide invaluable support in the preparation of a comprehensive specification for the official call for bids. The assistance of consultants and of international organizations may also be useful.

The following sections do not describe how to prepare a BIS, but they contain an overview and helpful tips regarding the preparation of a comprehensive tender document, along with the invitation to bid, some bid evaluation techniques, the compilation of contracts, terms and conditions, and interface requirements before and during the LTO project execution.

A first step before issuing a BIS document should be a comprehensive study on the preparation of the detailed scope specification. The technical specifications used in the BIS should contain all the technical details, along with the complete scope of supply, including services. They should be written in such a way as to avoid the unnecessary exclusion of any qualified local or international bidders. The BIS should also include all the legal and regulatory requirements, those stemming from safety, technical, economic and financial evaluations, and from feasibility studies and an EIA.

The type of contract under which the LTO project is executed (turnkey, split package or multiple package) will have a large impact on the style and contents of the BIS. With split or multiple package contracts, the BIS can be divided into delivery packages, but this should be done with a clear understanding and communication of the division of responsibilities. Alternatively, the BIS could be issued to the general contractor overseeing the whole project and to subcontractors to whom specialty packages may be assigned. The BIS for an NPP LTO project should be issued to both the national and international circles, in order to obtain the broadest and most competitive bids.

The BIS should provide all the data and information necessary to the contractors for their bid submissions and require that the necessary engineering work be supported by R&D efforts where necessary. It should contain legal requirements as well as the necessary licensing documentation for the planning and execution of the LTO project. The specifications must also include the limits and margins of acceptance. These margins must be as per standards and code requirements, never beyond, too rigid, below or too lenient.

At a minimum, the BIS should include the following main topics:

— The contract approach;
— Details on the site and on the services already available at the site;
— All technical requirements at the site, including seismic and environmental;
— The bidding conditions;
— The bid development criteria, and possibly a sample table of contents;
— Administrative instructions, inclusive of security clearance requirements;
— Safety philosophy and licensing requirements;
— Scope of the supply and services required;
— Quality assurance programme of the bidders/contractors and of the owner/operator;
— Quality assurance and quality control certifications, verifications, on-site inspection requirements, factory acceptance test requirements;
— Definition and scope of the interfaces;
— A list of the required certifications and of the applicable codes and standards;
— The owner's scope of supply and services;
— The timeline and the overall project schedule;
— Commercial terms and conditions, including the outline of a draft contract;
— Spares requirement and availability for the plant lifetime.

A detailed and comprehensive BIS is essential to the proper and smooth execution of the project. An ambiguous and incomplete BIS document allows bidders/contractors to make their own assumptions, which often lead to higher prices, conflicts and project delays. A comprehensive, well written BIS would also facilitate the owner/operator's subsequent task of evaluating the bids.

6.2.3. Quality assurance requirements in the bid invitation specification

A programme of checks and reviews of the quality of the work of contractors, service providers and installers is part of the main responsibilities of an NPP owner/operator engaged in an LTO project. This programme should be imposed by contract and included in the BIS as a requirement for quality control, quality assurance witness points and quality assurance hold points at various stages of the LTO project execution.

Quality control, quality assurance witness points and quality assurance hold points should be integrated with:

— Technical inspections of the design documents and the validity checks of the data supplied;
— Technical acceptance of the fabrication/manufacturing steps at the supplier's site.

Quality assurance reviews of the quality assurance programmes of suppliers, bidders, manufacturers, service providers and of the documentation they submit should be conducted by the owners or their representatives.

Quality assurance and quality control reviews and review milestones should extend not only to the physical activities (equipment manufacture and material supplies), but also to desktop activities, beginning with the feasibility study consultant services. The owner must ensure the correct input and execution of the feasibility studies, paying particular attention to the finalization of the data and the replacement of all preliminary assumptions with hard data from the selected suppliers. The same level of scrutiny should apply to the consultants who authored the BIS and those who later carry out the bid evaluation. A delicate task is scrutinizing the motivations leading to the recommended bid and the final vendor selection.

An independent team of quality assurance inspectors and experts should review the BIS draft. Technical specialists should be supporting quality assurance and quality control staff in the BIS review itself. All changes agreed upon must be included as requirements in the BIS and in the contracts.

Figure 15 is a graphical representation of a bid execution process.

6.2.4. Contract approaches for long term operation

The plant owner/operator normally decides on the contractual approach for the project based on his or her own technical and administrative ability to manage the project and the availability of resources. This decision will largely affect the bid evaluation process and the scope of the economic bid evaluation. Three main types of contracts have been commonly used for LTO and other projects:

— *Turnkey contracts.* A single main contractor, or a consortium of contractors headed by one holding entity, takes the overall responsibility for completing all phases of the project, including design and documentation.
— *Split package contracts.* The overall responsibility for design, material supply and project implementation is divided among a relatively small number of large contractors. Each contractor is separately in charge of a portion of activities/work. This requires a control authority with an adequate mandate and resources to oversee the coordination of all activities.
— *Multiple package contracts.* The owner/operator, with the assistance of consultants/experts, is responsible for managing the engineering of all improvement tasks and overall project implementation. A large number of contracts are issued and several contractors are tasked with smaller parts of the overall project. A clear division of responsibilities is key to successful project implementation. Interface coordination rests with the owner/operator and the prime consultants. In multiple package contracts, the services will come from different contractors. Services may include detail engineering, planning, HR management, training, security, catering, parking, health and radiation protection, various construction specialties, material management, equipment storage, preservation and distribution, decontamination, demolition and waste disposal, water treatment, SSC installation, testing, and commissioning of LTO improvements and of the integrated systems. In this latter type of contractual arrangement the owner/operator assumes a large portion of the overall responsibility. It is normally reserved for large national utilities with extensive resources.

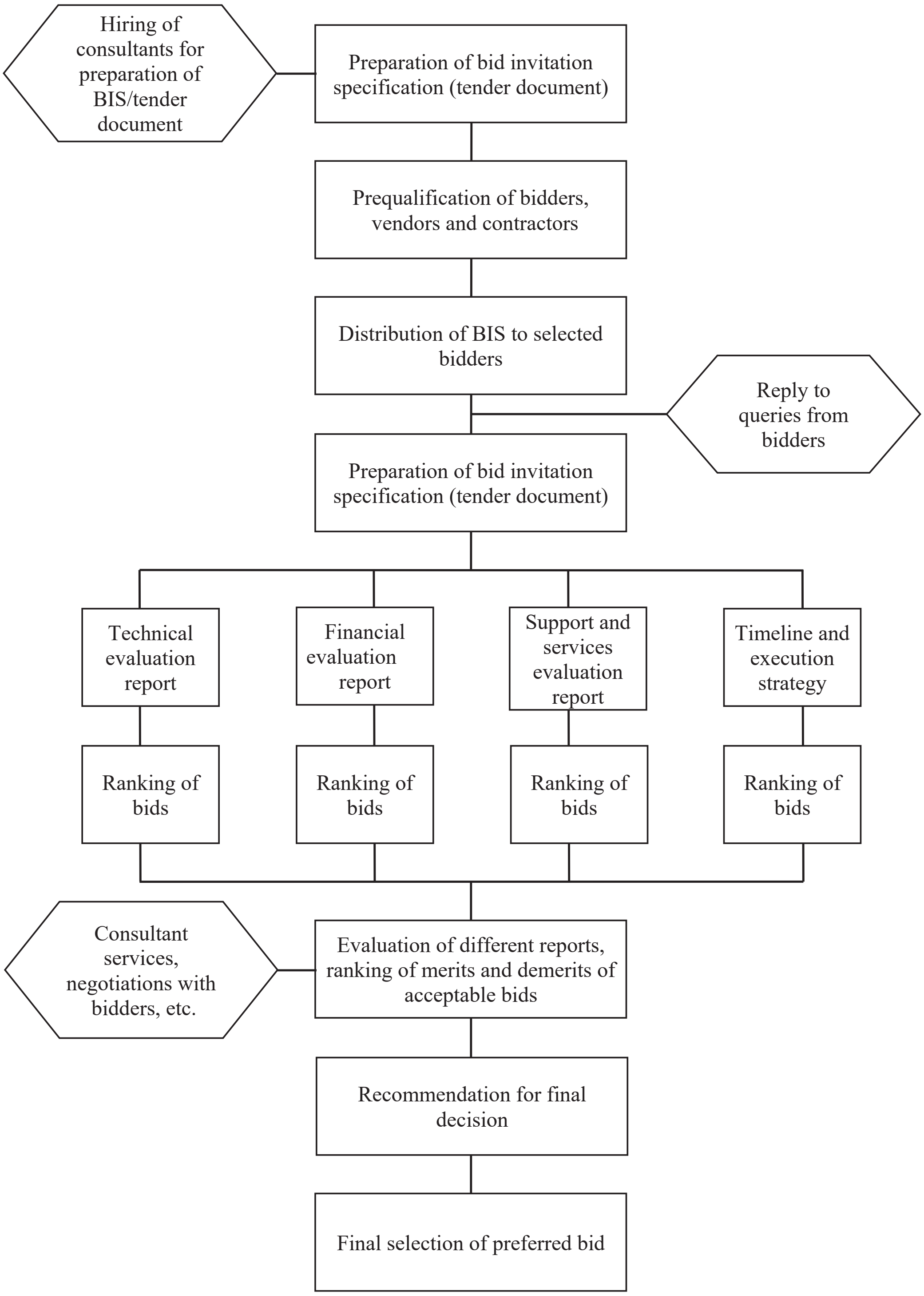


FIG. 15. Bid execution process [39].

In turnkey contracts, the contracting organization or consortium is fully responsible for planning, managing all quality functions and for successful project completion, including commissioning and turnover to operations.

In split package and in multiple package contracts, the owner's organization may have its own design authority or use an outsourced design group, or both, to coordinate the contractors' interfaces and for coordination between the design authority and the licensing authorities. In split contracts, the splits are few and they can cover very large scopes, even the nuclear island, conventional island and balance of plant. In such a three way split, the main contractors can be issued three turnkey contracts.

If the splits are done by discipline (civil, mechanical, I&C or electrical), the contracts should be considered multiple package contracts. In multiple contracts, the owner/operator usually decides on the division of responsibilities in concert with the main contractors, not only for the project work but also for the final quality and reliability checks of the complete scope of work, including implementation, testing and commissioning.

Because of the complexity of multiple contracts, the owner/operator should conduct a careful contract approach study. The study should examine the risks of each approach (e.g. for split contracts the risk of one delay and of its cascading effects on other activities on outage, etc.), including their particular economic aspects, such as the costs of controlling interfaces, the greater or lesser complexity of project management and the political and legal implications of each contractual approach. The feasibility of having two or more contractors sharing the same working area should also be studied in detail with all the interface and coordination controls required.

Each contract approach has its own advantages and disadvantages in terms of the financial, economic, technical, social and political impacts. Contractual details are usually country specific and utility specific. They also depend on the reactor type, on the reactor service life and on the type of LTO related improvements. The main advantages and disadvantages of each contract type are summarized in Table 11.

The more the scope of work, supplies and services are subdivided among various organizations, the greater the number of interfaces required. The additional costs for interface control and project management have to be carefully estimated.

All bids should be aligned for scope, content equivalence, warranties, schedules, delivery dates, quality, performance, materials, services and the like. The alignment details should be negotiated with the bidders, to enable the owner/operator to conduct an equitable bid evaluation.

The various contractual items have to be checked with respect to their cost consequences and their overall economic impact in case of delays in one or another part of the project. In general, the more the contract

TABLE 11. ADVANTAGES AND DISADVANTAGES OF EACH CONTRACT TYPE

Advantages to the owner	Disadvantages to the owner
Turnkey contract:	
Minimum management of interfaces Lower engineering cost Minimum risk of schedule delays Minimum coordination efforts Overall harmonized approach Faster compilation of project documentation Maximum contractor support for regulatory requirements	Minimum project control
Split package contract:	
Increased project control Use of own capabilities Learning opportunities for local staff working beside experienced foreign staff Parallel work opportunities of two or more contractors or countries Moderate risk of overall project delays	Increased responsibility as a result of compatibility problems between systems Increased interface problems Increased management control and greater responsibility Licensing documentation risks
Multiple package contract:	
Opportunity to customize the project More on the job training/experience Procurement controlled by the project management company	Maximum owner’s responsibility for interfacing packages, component issues Maximum interface management control, quality assurance/quality control, resolution of poor system performance, commissioning of systems, maintaining the project schedule Licensing risks Large engineering staff required Risks of delays and increase in cost

responsibilities are subdivided, the higher the risks to the owner. The risks associated with different contract approaches must be assessed and their economic consequences analysed and translated into costs.

A draft contract must be prepared as part of the BIS documentation. The draft should be carefully checked for cost implications, both qualitatively and quantitatively. Table 12 is an example of a table of contents for a turnkey LTO contract.

A similar table of contents can be applied to the other types of contract approaches as well.

6.2.5. The bid evaluation process

In response to the BIS, a number of bids will be received from local and international bidders. The owner/operator is responsible for the entire bidding process, therefore, the technical, economic, financial and legal experts from the owner/operator's organization or delegates evaluate the bid. In some cases, assistance in special fields may be necessary and experienced consultants and specialists may be required to assist.

The main objective of the bid evaluation is to align all bids in a way that allows the comparison of all technical details of the LTO related improvement projects. This can be done by discipline, comparing the mechanical, electrical, I&C improvements, modification of civil structures or the construction of new structures, the equipment and system installation details, the interfacing between new and existing SSCs and the condition of existing SSCs. The bid evaluation should also cover R&D programmes, if any, the documentation required and the costs, including transportation, of all components.

Once the bids are collected and aligned, the owner's organization performs a bid assessment and economic evaluation, whose main activities include:

— Verification of the completeness of the supporting documentation and its compliance with the technical, economic, contractual and financial requirements, including completeness and compliance of any services provided in accordance with the BIS requirements;
— Identification of all deviations and/or alternatives;
— Preparation of queries on the bid contents and of the clarifications required;
— Preparation of a checklist for performance guarantees of plant availability, of material properties, of workmanship, of design margins, etc.;
— Assessment of commercial warranties such as project time, date of completion, etc.;
— Identification of uncertainties and risks (technical, commercial and financing);
— Assessment of the financing proposal in connection with the terms of payment;
— Identification of interfaces associated with the project for split contracts;
— Identification and documentation of penalties and bonuses associated with delay/early project completion.

At the end of the bid assessment process, the staff of the owner/operator will rank the valid bids in terms of merit, considering:

— The results of the technical bid evaluation;
— The capital cost;
— The commercial and contractual terms and conditions;
— The financial proposals;
— The participation of the owner/operator, if either split or multiple contract approaches are adopted.

While comparing/evaluating the various bids, any demolition and/or modifications of the existing installation required for proper integration with the new equipment should be carefully assessed. In most cases, the preparation work required varies from bid to bid. In addition, the owner should align the schedules and the durations of the outages as much as possible with all the bidders, since they may also be different from bid to bid. This must be done prior to awarding the contracts.

All risks should also be taken into consideration to prevent economic losses in the future and to avoid any technical, legal or administrative conflicts. Some of these risks include:

— Challenges integrating new equipment with existing SSCs;

TABLE 12. EXAMPLE OF A TABLE OF CONTENTS FOR A TURNKEY LTO CONTRACT

1. Definitions

2. Basis for the contract (LTO/PLEX, etc.)
   - 2.1. General
   - 2.2. Applicable codes, laws, regulations and requirements
   - 2.3. Contract documents, including correspondence and language
   - 2.4. Effective date of the work

3. Scope of supply and services
   - 3.1. General
   - 3.2. Scope of supply and services of the contractor
   - 3.3. Scope of supply and services of the utility
   - 3.4. Spares, consumables and damaged parts

4. Documents
   - 4.1. General
   - 4.2. Technical documentation: drawings, specifications, calculations, procedures
   - 4.3. Interface documents
   - 4.4. Licensing documents
   - 4.5. Technical documents for acceptance
   - 4.6. Non-technical documents, including commercial documents such as invoices, transport documents, tax and customs documents
   - 4.7. Construction, erection and operating procedures
   - 4.8. Commissioning procedures
   - 4.9. Operation and maintenance manuals

5. Contract agreement
   - 5.1. Proprietary information
   - 5.2. Assignment of work and subcontracting
   - 5.3. Quality assurance and quality control
   - 5.4. Rights of inspection at the facilities of subcontractors

6. Risks and liabilities
   - 6.1. Risks of loss or damage
   - 6.2. Non-nuclear liability
   - 6.3. Nuclear liability

7. Insurance
   - 7.1. General requirements
   - 7.2. Various types of insurance for the entire project

8. Licences
   - 8.1. Import–export licences
   - 8.2. Special permits requirements for the utility's country

9. Training of operating and maintenance personnel
   - 9.1. On the job training
   - 9.2. Simulator training
   - 9.3. Retraining

10. Contract schedule
    - 10.1. General project schedule
    - 10.2. Effective date and start of project
    - 10.3. Consequences of delays

11. Technical warranties and guarantees
    - 11.1. Design, materials and workmanship guarantees
    - 11.2. Plant performance guarantees
    - 11.3. Rectification of defects and failures
    - 11.4. Penalties and bonuses

TABLE 12. EXAMPLE OF A TABLE OF CONTENTS FOR A TURNKEY LTO CONTRACT (cont.)

12. Contractual price and financing
    12.1. Base price
    12.2. Price escalation and adjustments

13. Terms of payment

14. Force majeure

15. Termination of contract

16. Applicable laws

17. Jurisdiction: Disputes and arbitration

18. Organizational matters
    18.1. Representatives
    18.2. Addresses
    18.3. Shipment and transportation

19. Service contract

— Challenges with the life assessment and life management of irreplaceable components;
— Contractual challenges;
— Human performance issues;
— Financial issues;
— Political conditions;
— Environmental conditions.

A team of technical, economic, legal, financial and administrative experts should be constituted to supervise the complete process, starting from BIS preparation to bid evaluation, negotiations with bidders, finalization of the winning contract(s), contract preparation, and execution and successful completion of the LTO project. The team must evaluate all risks prior to finalizing the contracts for LTO. The bid evaluation and contract preparation experts should be independent of the implementation teams. They should be selected outside the pool of experts already assigned to the various LTO implementation tasks.

6.3. PLANT REFURBISHMENT PHASE

Once the contracts are awarded, the following expert functions will be required in support of the plant refurbishment phase:

— Detail planning, walkdowns and field engineering to install SSC changes and any new system additions;
— Demolition specialists to dismantle existing structures and remove old equipment;
— Construction contractors for new SSC installations;
— Commissioning specialists for testing, commissioning and return to service with replaced, refurbished and new SSCs.

6.3.1. Strategy for equipment replacement

Heavy component replacement projects, particularly those related to SSCs inside the reactor building, require specific considerations with regard to site preparation activities, safety, collective radiation dose, cost, sequence of activities and schedule. The individual component replacement strategy should be developed in close association with the component manufacturers and installers.

Each component replacement strategy [40] and its cost will be highly dependent on the type of component and on its technical specification, which can include:

- The replacement component supply scope, e.g. the specified length of the reactor coolant loop spool to be replaced; the replacement technique of the steam generators, whether supplied in one or two fragments; the reactor vessel head replacement specification, whether bare minimum or with welded CRDMs; the core shroud replacement specification in boiling water reactors (BWRs), whether complete or partial; the shipment method; the ground transportation method within the NPP site (e.g. the choice of the transportation path, the need for ground reinforcements, the component orientations); the need for temporary facilities on-site as, for example, a temporary facility for the steam generators, when end machining is performed on-site; and a temporary facility for welding a new or the old CRDMs to the replacement reactor vessel head or for machining the reactor coolant loop nozzles.
- The hoisting of the component inside the containment building and the overall handling sequence.
- The access route inside the containment building may require temporary demolitions to avoid interferences against existing design features such as SSCs along the access path and physical clearances of the main crane beams (two or three point lift, crane upgrading required, etc.).
- The need for temporary containment openings in the reactor building wall if one of the steam generators does not fit through the equipment hatch, either because of an unsuitable location or because its inner diameter may be too small. The cost of temporary openings will depend on whether the reactor building wall is made of pre-stressed or reinforced concrete. It will also depend on the choice of the opening location (roof or wall), on the design of the reactor building wall (integrated steel liner or epoxy finish), or the presence of interferences with external components (e.g. storage tanks, adjacent buildings, underground channels) that may limit the location of the temporary containment opening. The reactor building wall cutting technique also affects cost. Among the proven techniques are core drilling, diamond saw blade cutting, controlled hydraulic explosive, thermal or jet stream process.
- The design of the concrete and metal structures inside the containment building, which may require cubicles and concrete floors at various levels to be modified.
- Major refurbishments/replacement of non-safety equipment are usually aimed at improving the efficiency, availability and reliability of the plant, or at optimizing O&M costs. Some specific replacements/refurbishments may also be required if the option of power uprate is considered for the LTO process.

6.3.2. Material procurement and installation

During the LTO implementation phase, the following are required:

- Planning, layout and engineering of the refurbishments and of any new system additions;
- Experts in bid evaluation, contract preparation, contract placement and supervision;
- Safety specialists to prepare the licensing documentation (FSAR, environmental report, etc.), licensing submissions and other regulatory activities;
- Demolition specialists to dismantle existing structures and remove old equipment;
- Construction contractors for new SSC installations;
- Commissioning specialists for testing, commissioning and return to service with replaced, refurbished and new SSCs.

With regard to the main contractors, equipment vendors and suppliers are normally pre-qualified. The pre-qualification requires that these vendors offer recognized capabilities and experience, including qualified processes, for similar work in engineering, licensing, manufacturing and installation of the main components of the primary circuit in similar NPPs.

The process of selecting the final suppliers begins with a request for quotation (RFQ) sent to all the pre-qualified suppliers, inviting them to propose part or all of the scope of supply.

The RFQ should include the following elements:

— All relevant design documentation and as-built data concerning the component to be replaced, and its interfaces with the environment (inside and outside the containment building);
— A specific request for any modifications (interfaces, power upgrading or material improvement);
— Conditions of implementation (outage constraints);
— Possible replacement strategies.

The final orders will be placed only after an overall evaluation of the scope of supply with all possible strategies. The RFQ should give the potential vendors opportunities to propose several options to help the owner/operator optimize its choice.

When there are separate contracts for component fabrication and installation, the owner/operator should apply special care in assigning responsibilities for ensuring:

— The evaluation of any variance in detail specifications or outline geometry of the replacement components in relation to the interfacing plant systems, including any changes in the static and dynamic loading at the component boundary in relation to the licence requirements and to the integrity of the interfacing SSCs;
— The adequacy of the delivery method and of its location;
— The requirements for equipment protection for intermediary storage, if applicable;
— The piping and nozzle interfaces (end position and finish (bevelled or not), the accuracy of the metrology data, the welding qualifications, the accuracy of the requirements for any thermal treatment to be performed on-site, etc.);
— The adequacy and compliance of the equipment support interfaces (saddles/legs, skirts);
— The cleanliness and hydro test requirements versus the site capability to provide them;
— The adequacy of the manufacturing non-destructive examination report, wherever required;
— The testing requirements;
— The shipment and adequacy of the temporary parts requirements (blind flanges, bolting, etc.).

To facilitate the management of the interfaces, it is strongly advised to place the orders in logical packages (supply, engineering and installation), even if different suppliers are involved.

The owner/operator should give special attention to the installation of critical or sensitive components. These should be in the scope of the main installation contractor or of recognized experienced subcontractors. Sensitive components may include:

— Primary, secondary and auxiliary piping installation (seamless induction bending of large bore pipes, cutting, alignment, welding and non-destructive examination);
— Handling and hoisting of large components (steam generators, vessel head, etc.);
— Execution of the temporary containment building opening, etc.

Although the supply and delivery of large equipment is in most cases the critical factor of the overall scope, delaying the other work orders may induce cascading effects such as encroachments on the critical path and unnecessary overall schedule risks.

In terms of installation issues and threats to the project objectives, among the top LTO implementation risks that may substantially affect project costs and schedule are those related to underestimating installation/construction requirements in a radioactive environment and in older plant settings, with a greatly expanded work force of contractors, possibly inexperienced with work in radioactive environments. Some of the major setbacks encountered in past LTO projects have included:

— Unexpected major scaffolding requirements in older plants lacking access platforms, catwalks, etc.
— Setbacks in first of a kind upgrade designs (if any).
— Engineering errors due to poor configuration management and outdated documentation in older plants and serious unresolved access issues during engineering walkdowns.
— Unpredicted access routing issues for larger upgraded replacement equipment due to new seismic and environmental qualification requirements, higher loading, etc.

— Discovery work for previously undetected, ageing related damage (i.e clogging and corrosion of underground and buried piping).
— Planning and scheduling gaps (i.e. sequence and coordination gaps between operations permit windows, supply and installers).
— Unexpected detail engineering gaps in engineered change packages, resulting in rework and resubmissions for regulatory approvals and a large number of as-built changes, field engineering corrections, deviations and variances.
— Lack of preparation for:
  - Radically expanded material handling needs, i.e. increased material routing and poor organization of expanded internal transportation needs (lack of cranes and other material handling equipment, lack of routing plans, interferences, accessibility issues and timely material delivery issues);
  - Unexpected requirements for larger decontamination and radioactive waste management facilities;
  - Insufficient radiation detection equipment and increased breakdowns of existing equipment because of much heavier use with expanded human resources;
  - Unpredicted increase in plant access point requirements;
  - Expanded security requirements on-site;
  - Underestimated expansion of services in a radioactive environment, such as expanded health physics personnel;
  - Expanded requirements for lockers and changing room space, plastic and double plastic suits, tyvek suits, overalls, and greatly expanded specialized laundry facilities for contaminated clothes;
  - Underestimated expansion of washrooms, drinking water requirements, food service, parking facilities;
  - Underestimated expansion of utilities to support installation (compressed air, gas, service water, steam, power points, etc.);
  - Underestimated expansion of lighting facilities to allow work in areas normally without lighting and subjected to high temperatures and a harsh environment during normal operation;
  - Underestimated expansion of decontamination areas and facilities for contaminated materials, equipment and tools;
  - Expanded warehousing requirements and inventory control issues;
  - Expanded need for radiation protection training of contractors and a much greater number of expert escorts in top radioactive areas, etc.

Examples of LTO implementation projects and their status in a number of Member States are presented in Appendix V.

7. CONCLUSIONS

7.1. DECISION PROCESS

One of the most effective precursors of LTO is an effective PLiM programme throughout the NPP's design life. In general, the more ageing mitigation measures and improvements are implemented during the plant's operational history, the less onerous and more feasible the LTO option becomes.

Anticipating changes in the sociopolitical, industrial and market context and anticipating stakeholder expectations is essential in obtaining the data required for the proper development of an LTO economic evaluation and the accurate interpretation of its results.

A first concrete step towards an LTO project's economic and financial evaluation is the assessment of the current SSC conditions and the cost estimate of compliance with current safety regulations and with performance and reliability targets.

7.2. COST DRIVERS

The identification and selection of the cost drivers is an indispensable element in the economic and risk assessment, and in the development of an LTO project investment plan.

Cost drivers govern the budgets of both the project phase and the extended operation period of an NPP. They should be subjected to sensitivity analysis wherever uncertainties are identified.

Cost drivers vary from unit to unit and from operator to operator. Therefore, the owner/operator should carefully ascertain the cost drivers specific to the operating conditions, to the plant environment and to the corporate culture.

7.3. RISK MANAGEMENT

An integrated risk management process applied to an LTO programme aims at evaluating the impact of risks on KPIs and on financial goals. It can help identify and quantify the risks associated with LTO and other options, together with their impact on future technical and economic performance. Where required, it can help optimize the development of a risk mitigation plan, reducing the overall risk profile to acceptable levels.

Risk assessment methodologies should always be a key element in the economic and financial analyses of the profitability of LTO. By addressing all threats that may have an impact on the project's profitability, the risk assessment of all key technical, business, sociopolitical and regulatory input parameters can provide effective guidance in LTO investment decisions.

The methodology can be applied even to multiple LTO projects and hence allow the owner/operator to efficiently manage the risk profile of their reactor units or fleet, optimize the implementation time for each unit, the capital allocation and the overall budgeting process.

An integrated quantitative and probabilistic risk management framework should cover all project phases, from the feasibility assessment to the licensing, implementation and LTO period. In summary, it can effectively support the plant owner and the main stakeholders in their decision to proceed with LTO.

7.4. ECONOMIC ASSESSMENT

From an economic viewpoint, the decision to proceed with an LTO programme depends primarily on a comparison of the plant's marginal generation cost of operation, including maintenance, fuel and investment amortization, with the marginal generation cost of other electricity sources, with proper regard to the risks associated with each cost driver.

Comparative assessments should be conducted on key economic indicators used in the figures of merit (NPV or LCOE) for different market structures (regulated, deregulated) and for different types of economic assessments (whether at the company or at the national level).

In evaluating the future economic prospects of LTO, the owner/operator should focus on the unique circumstances affecting cost and performance, particularly on future demand and on the estimated price of electricity in the region. Sensitivity analysis should be conducted on the electricity price and on the other main economic parameters, such as the refurbishment investment cost, the decommissioning cost, the discount rate and carbon pricing.

Cost concepts used in LTO economic assessments conducted from a company perspective are different from those used in assessments conducted from a national perspective. Private costs are relevant from a company perspective; social costs are relevant from a national perspective. From a strategic viewpoint, social costs at the national level should be considered in comparative economic assessments.

Deregulation of the electricity market increases competition. Under such conditions, NPP owners tend to minimize the cost of plant management to remain competitive. They should, however, be cognizant of the fact that deleting or delaying improvement programmes during the plant's design life in order to reduce operating costs may hinder the economic feasibility of LTO.

7.5. IMPLEMENTATION

Detailed planning of an LTO project should include the identification of all interfaces and system integration aspects to help avoid interferences, conflicts and delays during the execution phase.

Close supervision of material quality, equipment delivery and installation is of paramount importance. The owner/operator or agent should closely control and coordinate the interfaces among all contractors, beginning with the conceptual and detail design agencies and spreading to system vendors, equipment and material suppliers, demolition and installation contractors, testing and commissioning contractors and field engineering support, to ensure compatibility of all new SSCs and total integration between new and old sections of the plant.

Among the least predictable LTO implementation risks that may affect project costs and schedule are underestimating material volumes and handling challenges, scaffolding requirements, volumes of radioactive waste, radiation protection and detection equipment, security equipment, lighting requirements inside the containment, laundry requirements for contaminated outfits, warehousing requirements, spare parts and consumable inventories, all hurdles that may arise from first of a kind designs (if any).

Testing and commissioning of integrated systems should be prepared in advance, to be conducted efficiently. Sufficient procedures, recording forms and engineering support should be available to help overcome issues that may arise.

Appendix I

COST DRIVER MATRIX

As shown in Section 3, a cost driver can be any activity or condition that causes a cost to be incurred by an organization. Cost drivers can be of an internal nature (labour, maintenance, fuel, nuclear safety improvements, performance related upgrades, etc.) or an external nature (externalities). Within the internal cost driver group, the costs of safety improvements are driven by the basic licence requirements that must be upheld throughout the length of the licence (including LTO). These are mostly linked to ageing management and ageing mitigation activities. When an SSC is identified as being safety significant, or a sequence of events in a risk analysis identifies a component as having even an indirect impact on safety, as defined by a significance criterion, then that component is said to be of safety significance. For example, during a seismic event, a non-safety component, located above a safety component, may be classified as being safety significant because it could fall onto the safety component and incapacitate it. This would impose a seismic qualification requirement on such a component.

Costs can also be of a non-technical nature. These are, for the most part, costs external to the organization, imposed from the outside, such as legal costs or periodic contributions to a decommissioning fund required by the nuclear legislation of a country. Other external costs could be imposed by regulatory requirements or generated by voluntary improvement programmes in response to operational feedback or even in anticipation of future regulatory requirements such as the changes driven by the lessons learned from the Fukushima Daiichi accident. Other external costs could be imposed by social forces or community needs, or even by a new electricity market position following the implementation of a deregulation policy.

Table 13 contains an example of a cost matrix developed in relation to an LTO project. The rows list the cost drivers and the columns the cost categories. The cells formed by the intersection of rows and columns contain the discounted costs of each activity.

Table 14 shows an example of a cost estimate template with the discounted costs of various improvement projects, such as repair and replacement options, and the probabilities that each such activity may be required for the various LTO durations being considered (10, 20, 30 years).

Table 15 shows a breakdown of the yearly financing costs required for the various improvements, inspections, testing and other activities in preparation for LTO prior to the end of the design life and those planned for the LTO outage prior to the licence extension.

Table 16 shows an example of a possible breakdown of the cumulative financial burdens by number of years and by currency, assuming the financing has foreign and local components.

Table 17 is an example of a template that could be developed to show the cost of financing from both internal and external sources broken down by lending institutions and by number of years. Such a template would show at a glance the complete financing panorama and help with the financing decisions and the wording of the lending contracts.

TABLE 13. COST DRIVER MATRIX

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1.0	Safety improvements/safety system additions to meet current regulatory requirements																							
1.1	Additions to meet single failure criteria																							
1.1.1	Addition of redundant safety I&C systems																							
1.1.2	Addition of second shutdown system																							
1.1.3	Addition of redundant power supplies																							
1.1.4	—																							
1.2	Improvement in redundancies of safety systems																							
1.2.1	Improvement in redundancy of power sources																							
1.2.3	—																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1.3	Addition of redundancies of safety injection system and new systems to mitigate all possible postulated scenarios																							
1.3.1	Addition of redundancy in long term emergency core cooling injection system																							
1.3.2	Addition of one train to the forced emergency injection system																							
1.3.3	Addition of emergency feedwater system in case of station blackout																							
1.3.4	—																							
1.4	Addition of post-accident monitoring systems																							
1.4.1	Addition of a redundant reactor building pressure monitoring system																							
1.4.2	Safety parameter display system																							
1.4.3	Critical parameters display system																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2.0	Surveillance/monitoring of life limiting critical non-replaceable SSCs in support of life assessment and ageing management functions																							
2.1	RPVs of PWRs/BWRs																							
2.1.1	R&D work for analysis and reduction in radiation embrittlement process																							
2.1.2	Annealing of RPV to mitigate radiation embrittlement																							
2.2	Containment																							
2.2.1	Inspection of containment structures and containment liner																							
2.2.2	Identification and mitigation of age related containment degradation																							
2.2.3	—																							
3.0	Safety upgrades/replacement/ refurbishment to meet regulatory, PSR, revised FSAR requirements																							
3.1	Heavy component replacements																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
3.1.1	Replacement reactor pressure vessel head and internal																							
3.1.2	Steam generator replacement																							
3.1.3	Pressurizer																							
3.1.4	Primary pressure boundary piping and structures																							
3.1.5	Reactor coolant pumps																							
3.1.6	Nuclear class pumps																							
3.2	Documentation																							
3.2.1	Commissioning reports analysis																							
3.2.2	Safety re-evaluation																							
3.2.3	Regulatory inspection																							
3.2.4	Revised monitoring and inspection procedures																							
3.3	Return to service																							
3.4	—																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
4.0	Spent fuel storage bay/pool management																							
4.1	Condition assessment of spent fuel storage bay condition																							
4.2	Space assessment for accommodation of LTO duration fuel																							
4.3	Development of high density tray racks for stacking used fuel to create extra space																							
4.4	Development of dry fuel storage facility																							
4.5	—																							
5.0	Conventional system modifications, replacements and refurbishments																							
5.1	Turbine generator overhauling																							
5.1.1	Low pressure/high pressure blade replacement																							
5.1.2	Generator stator rewinding, etc.																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
5.1.3	Steam generator and hydraulic system refurbishment																							
5.2	Condenser retubing/replacement																							
5.3	HVAC system improvement																							
5.4	Selected power and control cables																							
5.5	Pump house equipment replacement																							
5.6	—																							
6.0	Technological upgrades (obsolescence)																							
6.1	I&C systems																							
6.1.1	In-core, ex-core instrumentation																							
6.1.2	Control room, electronic room and field instrumentation																							
6.1.3	Plant protection, engineered safeguard and process instrumentation system																							
6.1.4	—																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
6.2	Electrical systems																							
6.2.2	High voltage switch gears																							
6.2.3	Line transformer protection relays																							
6.2.4	Medium voltage/low voltage switch gears and electrical distribution rooms																							
6.2.5	—																							
6.3	Plant computers																							
6.4	Communication systems																							
7.0	Equipment qualification																							
7.1	Mechanical equipment																							
7.1.1	Safety system mechanical equipment analysis to meet new standards																							
7.1.2	Replacement of non-qualified equipment																							
7.2	Electrical/I&C equipment																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
7.2.1	Qualification assessment of safety and non-safety electrical/I&C																							
7.2.2	Corrective measures for qualification																							
7.2.3	—																							
8.0	Safety improvements and initiatives in response to the Fukushima Daiichi accident																							
8.1	Electrical supply systems																							
8.1.1	Procurement of portable and mobile generators																							
8.1.2	Addition of DC batteries																							
8.1.3	—																							
8.2	I&C systems																							
8.2.1	Redundant power supplies for essential safety related I&C																							
8.2.2	Hydrogen monitoring instrumentation																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
8.2.3	Addition of accident monitoring instrumentation																							
8.2.4	Segregation of redundant safety injection system instrumentation																							
8.3	Core, spent fuel and containment cooling																							
8.4	Containment ventilation																							
8.4.1	Filtered/non-filtered																							
8.4.2	—																							
8.5	Hydrogen hazard mitigation																							
8.5.1	Installation of passive auto catalytic recombiners																							
9.0	Modification/improvement in management programme																							
9.1	—																							
10.0	Radiation monitoring facility upgrade and dose control																							

TABLE 13. COST DRIVER MATRIX (cont.)

Item	Description	Category *1	Type *2	Feasibility	R&D	Engineering	Bid evaluation procurement and supply of material	Transportation	Construction	Commissioning	Documentation and acceptance	Training	Spares backup and technical support	Operation	Maintenance	Contingency and others	Total	Discount rate	Period of utilization	Period of return	Expected yearly instalments	Expected impact on per unit cost	Prob. [%] *3	Remarks
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11.0	Public acceptance																							
11.1	Open meetings with the general public, civil society and media																							
11.2	Information sessions																							
11.3	—																							
12.0	Licensing process																							
13.0	O&M cost																							
14.0	Cost of LTO outage																							
14.1	—																							
15.0	Decommissioning cost																							
15.1	—																							
16.0	LTO project management and implementation cost																							
17.0	Overall risk assessment																							
17.1	—																							
18.0	Other remaining costs																							

TABLE 14. COST ESTIMATE TEMPLATE (ONLY FOR REPAIR/REPLACEMENTS/REFURBISHMENTS)

Component	Replacement cost (A)	Refurbishment cost (B)	Long term operation, 10 years				Long term operation, 20 years				Long term operation, 30 years				
			Replacement probability (%) (C)	Refurbishment probability (%) (D)	Expected cost replacement A × C	Expected cost refurbishment B × D	Replacement probability (%) (C)	Refurbishment probability (%) (D)	Expected cost replacement A × C	Expected cost refurbishment B × D	.	.	.	.	.
RPV head															
RPV internal															
Steam generator															
Reactor protection system															
Engineered safeguard systems															
Emergency diesel generators															
Turbine/generator															
—															
Grand total															

TABLE 15. FINANCE REQUIREMENTS

Finance required for year

No.	Activity	Period prior to end of design life												LTO relicensing outage									
		5 years			4 years			3 years			2 years			1 years			Y-1			Y-2			Total
		Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	
1	Safety improvements/safety system addition to meet current regulatory requirements																						
2	Surveillance/monitoring life assessment and ageing management of life limiting critical non-replaceable SSCs																						
3	Inspection of containment structures and containment liner																						
4	—																						
	Grand total																						

TABLE 16. BREAKDOWN OF CUMULATIVE FINANCIAL REQUIREMENT BY NUMBER OF YEARS

Finance required for year

No.	Requirement for all activities	Period prior to end of design life												LTO relicensing outage									
		5 years			4 years			3 years			2 years			1 years			Y-1			Y-2			Total
		Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total	
1	Feasibility																						
2	Research and development																						
3	Technical requirement																						
4	—																						
	Grand total																						

TABLE 17. OVERALL BREAKDOWN OF FINANCIAL ARRANGEMENTS/REQUIREMENTS

No.	Finance	Year						
		5 years	4 years	3 years	2 years	1 year	Y-1	Y-2
1	Local finance: Internal Reserved Utility/owner resources Reserved funds (decommissioning, etc.) Loans from local banks/financial institutions Borrowing from corporate office Borrowing from local banks/government, etc.)							
2	Foreign exchange: Loans from foreign banks/firms Partnership with foreign companies/countries Joint venture							
3	-----							

Appendix II

EXAMPLE OF AN ECONOMIC ASSESSMENT IN THE CZECH REPUBLIC

II.1. INTRODUCTION

One of the four units of the Dukovany NPP in the Czech Republic has been in operation since 1985 and its original design life was 30 years. In the 1990s, the operator decided to prepare the plant for LTO. One of the first steps undertaken was a techno-economic feasibility study that took two years to complete (2006 and 2007). This study provided the information necessary to support the operator's decision to proceed with LTO and decide its optimal duration. The feasibility study developed:

— The economic parameters needed to define the most profitable duration for LTO (+10, +20 or +30 years beyond the original design life);
— The basis for an effective LTO assurance programme;
— The economic planning methods and the tools to help implement the NPP extended service life management programme.

II.2. METHODOLOGY

The study was conducted in two steps (technical and economic) with clearly defined interfaces. The technical study indicated the types of improvements and the cost of implementing the measures necessary to prepare the plant to continue operation beyond the originally licensed service life. The economic study was based on the use of two main economic parameters to compare the different LTO options in the study. They were the NPV and the levelized production costs.

The 13 cost drivers defined in Ref. [2] were used to assess the unit's LTO:

— Safety upgrades to meet regulatory requirements;
— Other non-safety and conventional system upgrades to improve performance;
— Management programmes and processes;
— EIA;
— Maintaining expertise;
— Public acceptance;
— Radioactive waste and spent fuel management;
— Decommissioning;
— Licensing process;
— O&M review;
— Operating spares and consumables;
— Fuel cycle improvements;
— Overall risk assessment.

The first two cost drivers listed in the IAEA report were replaced by one called 'measures necessary to ensure that critical SSCs will last for the LTO period'. Under this cost driver, plant life limiting components and high cost SSCs were selected and grouped as:

— *Plant life limiting SSCs,* which are the irreplaceable components such as the reactor pressure vessel, the containment structures or those that are economically irreplaceable, for example, steam generators.
— *High cost components,* which are either those whose replacement would require very high investment levels (reactor internals, control rod drives, other primary components) or those whose sheer number and wide distribution throughout the NPP (cables, valves and actuators, etc.) would make them complex and costly to

handle. Other components that cannot be replaced are those that are obsolete or out of production (e.g. old I&C systems).

A life assessment was made for each of the SSCs in these groups. These assessments and the component prognosis were based on:

- The results of the NPP life management programme, including the results of AMPs, typical TLAAs, obsolescence management and health monitoring history.
- Safety upgrade requirements resulting from PSRs, international review missions, the post-Fukushima stress tests and specific expert opinions.

For those SSCs with a prognosis shorter than the start of LTO, necessary measures were suggested such as replacements, modifications, reconstructions, repairs or new ageing management mitigation actions. Where it was deemed appropriate, equivalent but less onerous measures were studied and adopted. Costs were estimated based on the experience of equal or similar measures implemented in other parts of the same NPP or in similar NPPs in the industry at large. Where there was a lack of experience, costs were based on vendor opinion with the approval of the design authority. The schedule to which each measure was implemented depended on:

- The SSC's expected remaining life;
- The SSC's expected remaining life after the measure was implemented;
- The duration of LTO;
- The planned unit outages and their duration.

After all cost drivers were reviewed, the related costs were estimated and the overall risk assessment was performed. The economic parameters NPV and levelized production costs were determined using a typical economic model with the following inputs:

- Costs of the improvement measures defined in the technical evaluation study;
- Normal NPP operating costs, such as fuel, labour, materials, insurance and decommissioning costs;
- Other necessary costs based on estimates of future developments in the electricity market, including electricity price predictions;
- The cost of carbon dioxide credits and different trading methods;
- The discount rate.

Various LTO duration scenarios were compared with other possible sources of electricity (e.g. new NPPs, fossil power plants).

The NPVs for +10, +20, +30 years of LTO and the technical feasibility of each duration were assessed, but a risk assessment was also conducted by estimating the accuracy of the input data (electricity price, fuel price, etc.) and the probability that the calculated NPVs were correct. A plan was also developed to reduce, eliminate or manage these types of technical risks by excluding or restricting selected forms of NPP operations.

Examples of non-technical types of risk include:

- Market risks (prices of commodities, services, exchange, interest rates, etc.);
- Credit risks (outstanding items, defaults);
- Operational risks (production, distribution, IT support, internal and external hazards, etc.);
- Entrepreneurial risks (company policy, government, regulators, etc.).

Sensitivity studies on these types of risks were conducted to obtain the most probable economic results. Specific risks were estimated through an expert opinion survey. Special questionnaires were developed and distributed to about 50 experts from the industry, governments, universities and R&D organizations.

Figure 16 shows the development process used to decide the most appropriate risk mitigation measures.

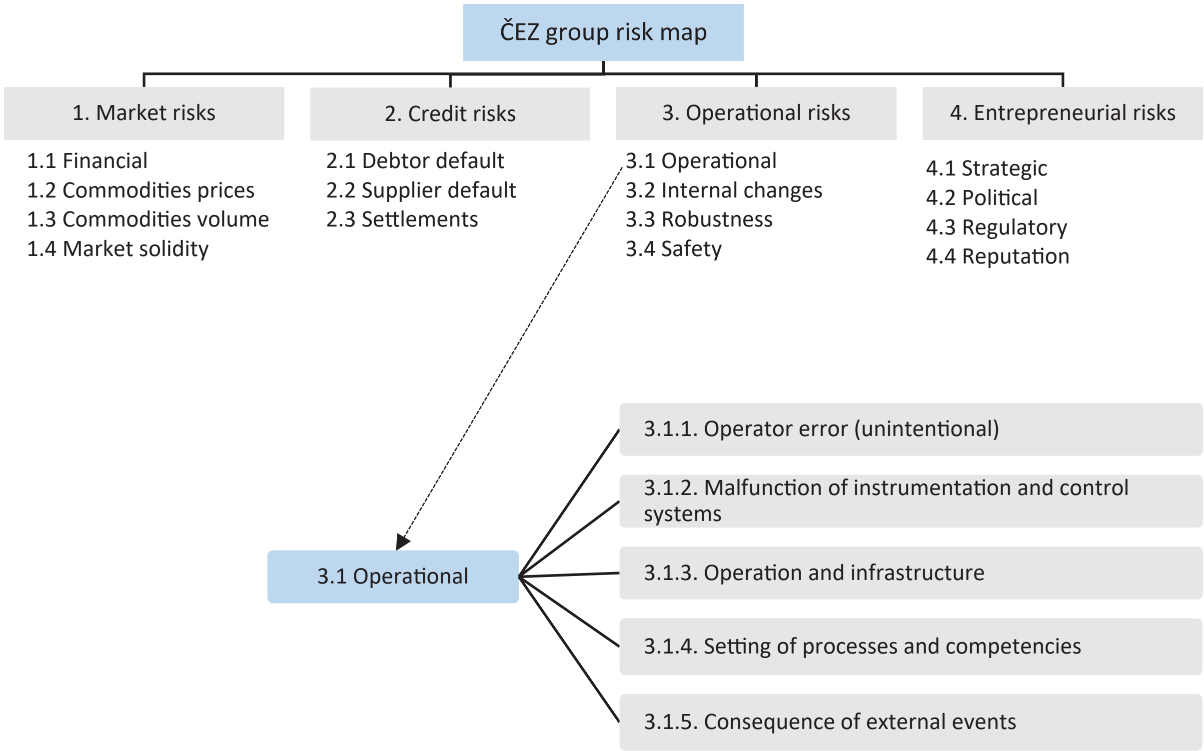


FIG. 16. Map of the main risk areas.

II.3. SOFTWARE SUPPORT

To support the technical portion of the technical evaluation study, a database application was developed with the following three main tracks:

— Evaluation of all cost drivers;
— Planning of the implementation of the proposed improvement measures;
— Data exports/extractions for the economic assessment and for presentations.

Figures 17–21 show some of the dialogue windows of this engineering tool:

— Main data entry window;
— SSC selection and grouping window;
— Evaluation dialogue window;
— Proposed improvement measures dialogue window;
— Cost data form.

II.4. RESULTS

The technical evaluation determined the costs of the necessary improvement measures to prepare for LTO over and above the normal plant operating costs. These measures were exported to the overall NPP LTO investment plan (from the database to Excel sheets). The Excel results are also shown in Figs 22–25.

The results showed the profitability of the LTO of Dukovany NPP. The most profitable option was the longer 30 year life extension, for a total of 60 operational years. The study also showed that this lifetime extension was technically feasible. None of the risks were estimated to be serious enough to cancel the project. Most of the risks were manageable; six risks were considered medium level. Only two risks were deemed capable of serious consequences:

— An unexpected reduction of the life expectancy of the hard to replace components that were not replaced, but whose ageing was mitigated;
— Targeted sabotage or terror attacks.

It was estimated that these two risk factors could move the value of the NPV outside its stochastic simulated limits, even with the inclusion of the funds necessary for the mitigation of these risks. However, if, instead of focusing on the consequences, these risks were seen from the point of view of their probability of occurrence, they became acceptable and this is what tilted the scale in favour of LTO.

Six risks were characterized as medium. Special attention was paid to those with the highest occurrence, such as the loss of experienced technical personnel in the R&D and technical service organization areas during LTO. All human resource experts agreed that this would be a serious problem that should be resolved by inter-institutional dialogue and inter-industry exchanges, and not only through recruitment. This is especially applicable to countries with small nuclear power programmes lacking a large pool of experts.

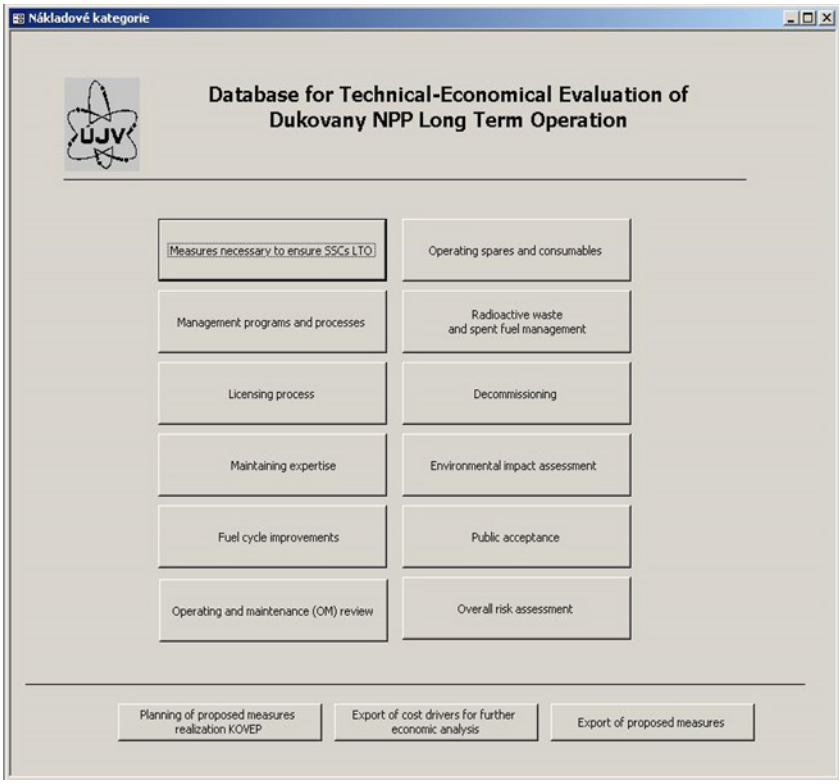


FIG. 17. Engineering tool for the technical part of the techno-economic assessment — main data entry window.

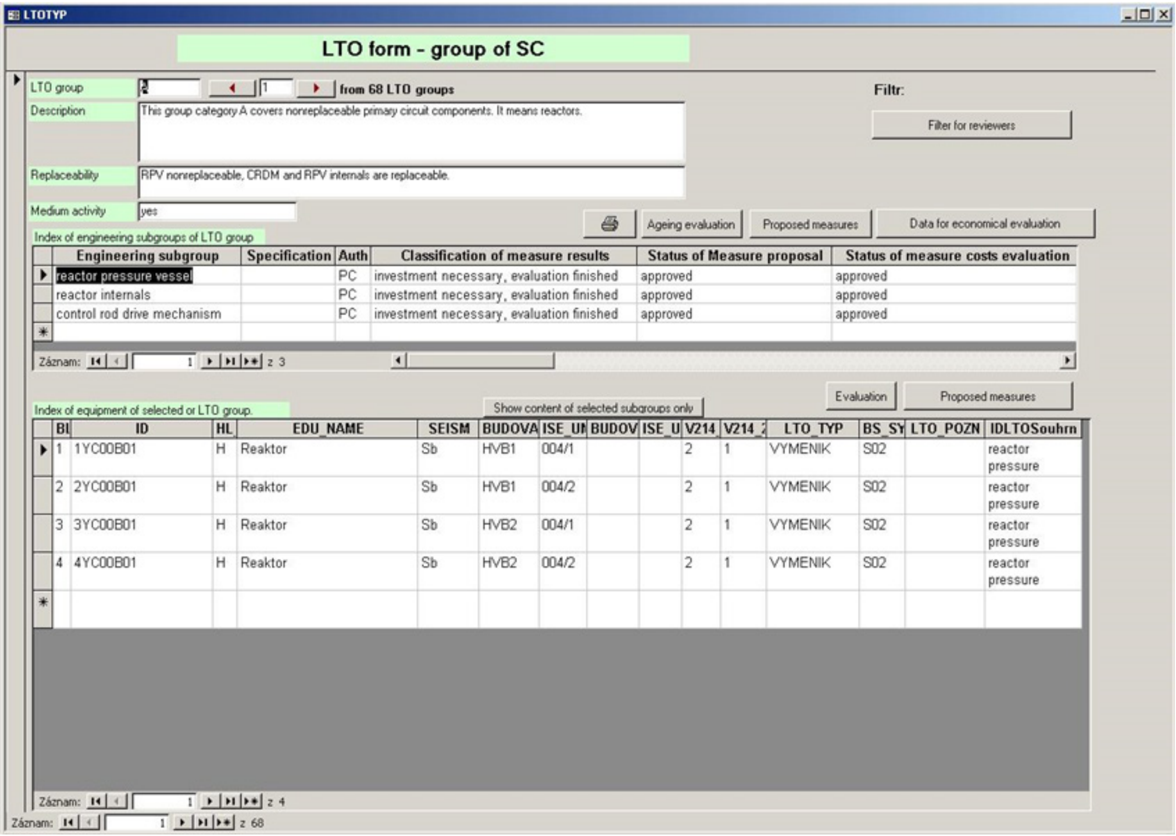


FIG. 18. Engineering tool for the technical part of the assessment — SSC selection and grouping window.

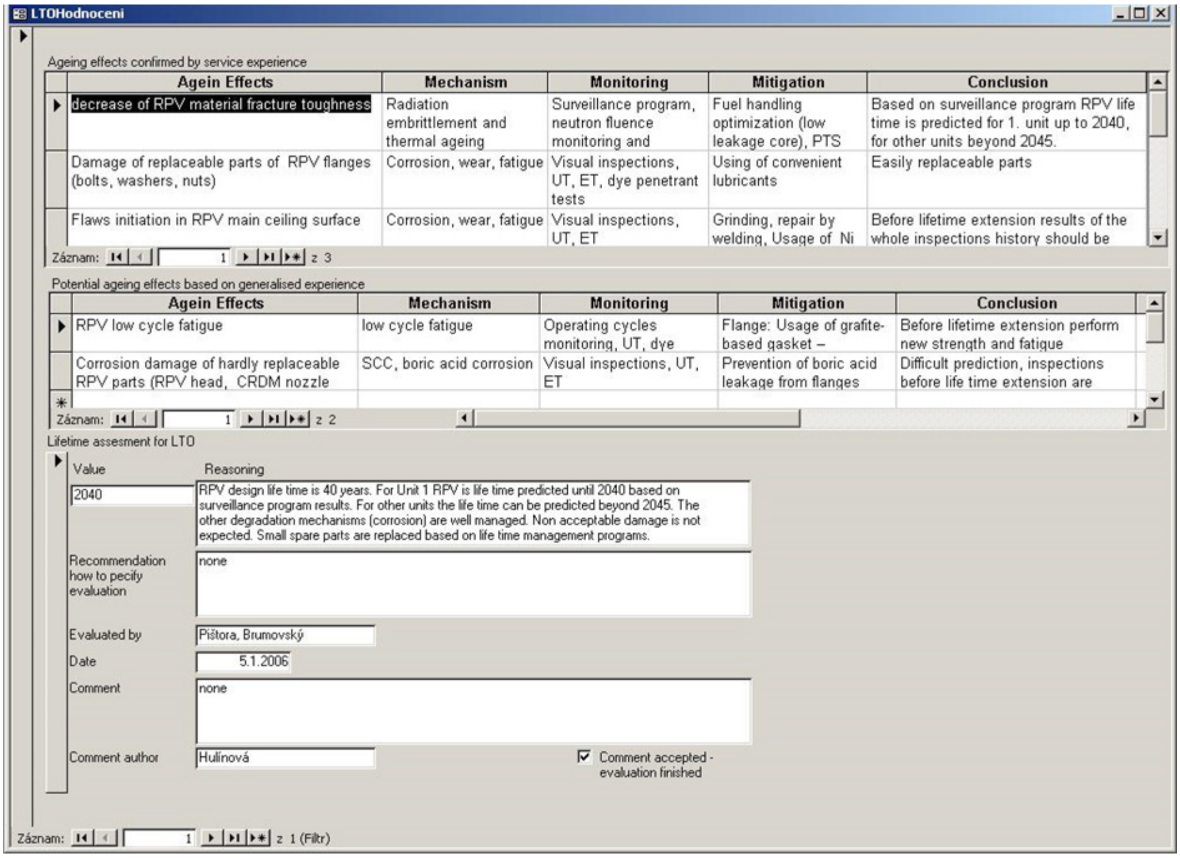
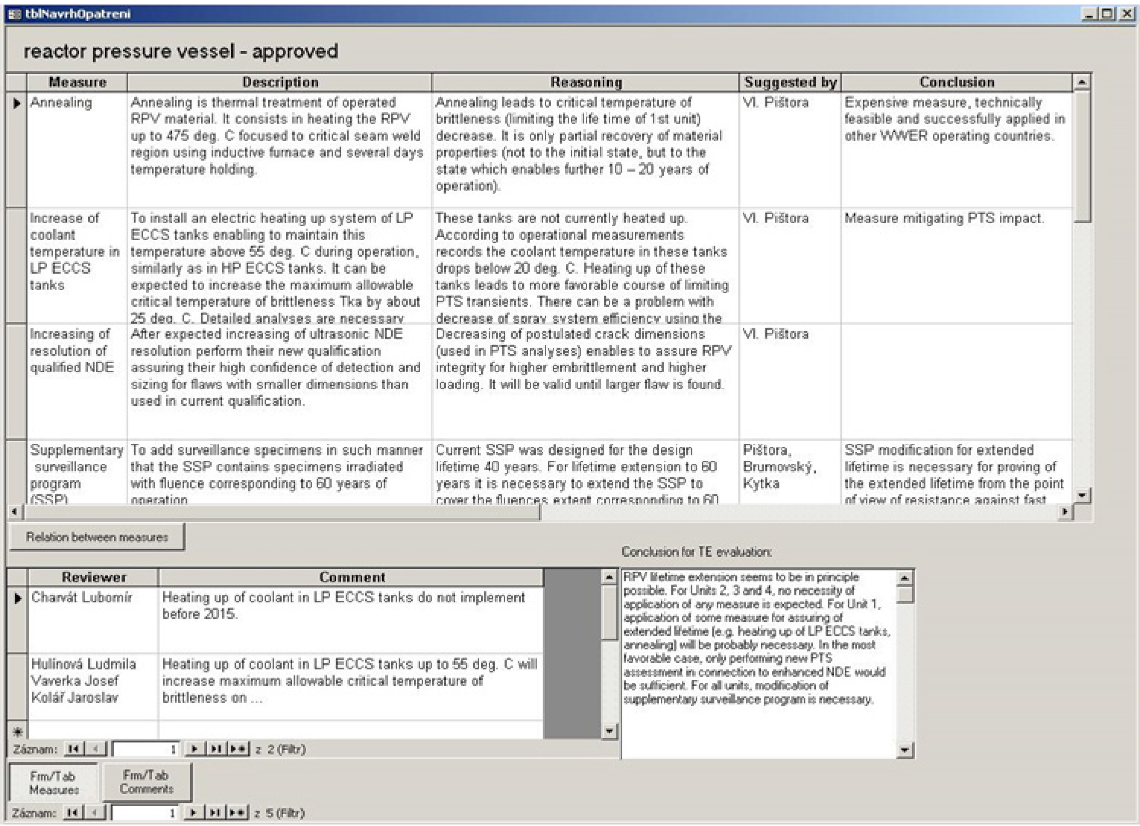


FIG. 19. Engineering tool for technical assessment — main evaluation window.



tblNavrhOpatreni

reactor pressure vessel - approved

Measure	Description	Reasoning	Suggested by	Conclusion
Annealing	Annealing is thermal treatment of operated RPV material. It consists in heating the RPV up to 475 deg. C focused to critical seam weld region using inductive furnace and several days temperature holding.	Annealing leads to critical temperature of brittleness (limiting the life time of 1st unit) decrease. It is only partial recovery of material properties (not to the initial state, but to the state which enables further 10 – 20 years of operation).	Vl. Pištora	Expensive measure, technically feasible and successfully applied in other WWER operating countries.
Increase of coolant temperature in LP ECCS tanks	To install an electric heating up system of LP ECCS tanks enabling to maintain this temperature above 55 deg. C during operation, similarly as in HP ECCS tanks. It can be expected to increase the maximum allowable critical temperature of brittleness Tka by about 25 deg. C. Detailed analyses are necessary	These tanks are not currently heated up. According to operational measurements records the coolant temperature in these tanks drops below 20 deg. C. Heating up of these tanks leads to more favorable course of limiting PTS transients. There can be a problem with decrease of spray system efficiency using the	Vl. Pištora	Measure mitigating PTS impact.
Increasing of resolution of qualified NDE	After expected increasing of ultrasonic NDE resolution perform their new qualification assuring their high confidence of detection and sizing for flaws with smaller dimensions than used in current qualification.	Decreasing of postulated crack dimensions (used in PTS analyses) enables to assure RPV integrity for higher embrittlement and higher loading. It will be valid until larger flaw is found.	Vl. Pištora	
Supplementary surveillance program (SSP)	To add surveillance specimens in such manner that the SSP contains specimens irradiated with fluence corresponding to 60 years of operation	Current SSP was designed for the design lifetime 40 years. For lifetime extension to 60 years it is necessary to extend the SSP to cover the fluences extent corresponding to 60	Pištora, Brumovský, Kytka	SSP modification for extended lifetime is necessary for proving of the extended lifetime from the point of view of resistance against fast

Relation between measures

Reviewer	Comment
Charvát Lubomír	Heating up of coolant in LP ECCS tanks do not implement before 2015.
Hulínová Ludmila Vaverka Josef Kolář Jaroslav	Heating up of coolant in LP ECCS tanks up to 55 deg. C will increase maximum allowable critical temperature of brittleness on ...

Záznam: 1 z 2 (Filtr)

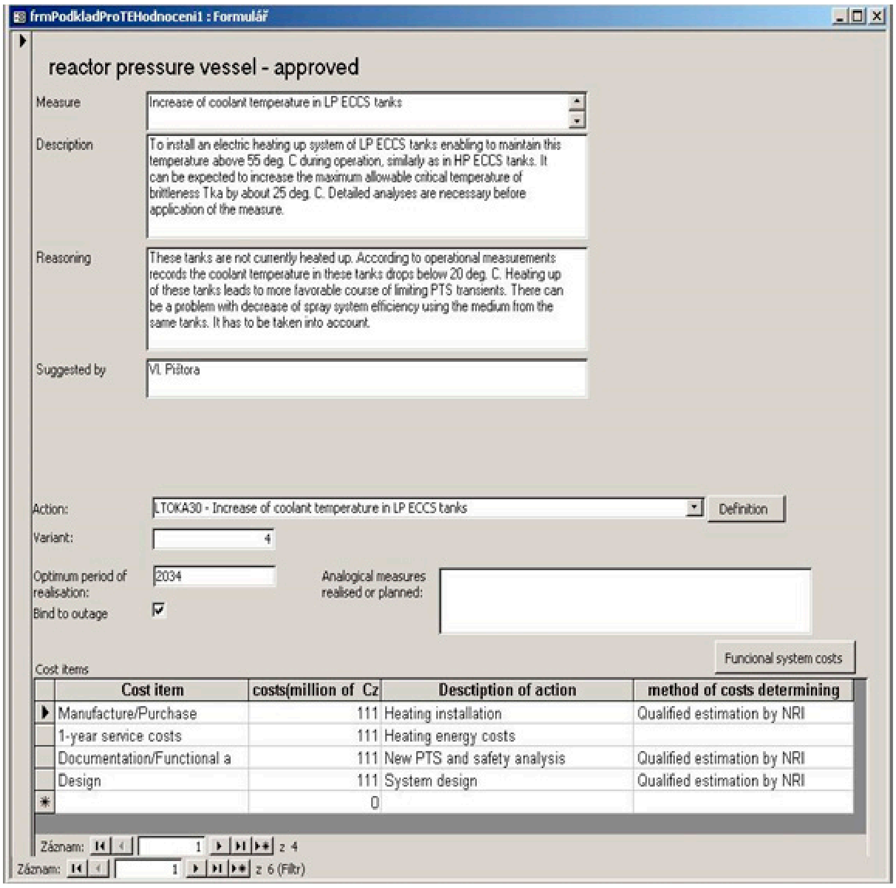
Conclusion for TE evaluation:

RPV lifetime extension seems to be in principle possible. For Units 2, 3 and 4, no necessity of application of any measure is expected. For Unit 1, application of some measure for assuring of extended lifetime (e.g. heating up of LP ECCS tanks, annealing) will be probably necessary. In the most favorable case, only performing new PTS assessment in connection to enhanced NDE would be sufficient. For all units, modification of supplementary surveillance program is necessary.

Frm/Tab Measures | Frm/Tab Comments

Záznam: 1 z 5 (Filtr)

FIG. 20. Engineering tool for the technical assessment — form for proposed measures.



frmPodkladProTEHodnoceni1 : Formulář

reactor pressure vessel - approved

Measure: Increase of coolant temperature in LP ECCS tanks

Description: To install an electric heating up system of LP ECCS tanks enabling to maintain this temperature above 55 deg. C during operation, similarly as in HP ECCS tanks. It can be expected to increase the maximum allowable critical temperature of brittleness Tka by about 25 deg. C. Detailed analyses are necessary before application of the measure.

Reasoning: These tanks are not currently heated up. According to operational measurements records the coolant temperature in these tanks drops below 20 deg. C. Heating up of these tanks leads to more favorable course of limiting PTS transients. There can be a problem with decrease of spray system efficiency using the medium from the same tanks. It has to be taken into account.

Suggested by: Vl. Pištora

Action: LTOKA30 - Increase of coolant temperature in LP ECCS tanks — Definition

Variant: 4

Optimum period of realisation: 2034

Analogical measures realised or planned:

Bind to outage: ☑

Funcional system costs

Cost items

Cost item	costs(million of Cz	Desciption of action	method of costs determining
Manufacture/Purchase	111	Heating installation	Qualified estimation by NRI
1-year service costs	111	Heating energy costs	
Documentation/Functional a	111	New PTS and safety analysis	Qualified estimation by NRI
Design	111	System design	Qualified estimation by NRI
	0		

Záznam: 1 z 4

Záznam: 1 z 6 (Filtr)

FIG. 21. Engineering tool for technical assessment — cost data form.

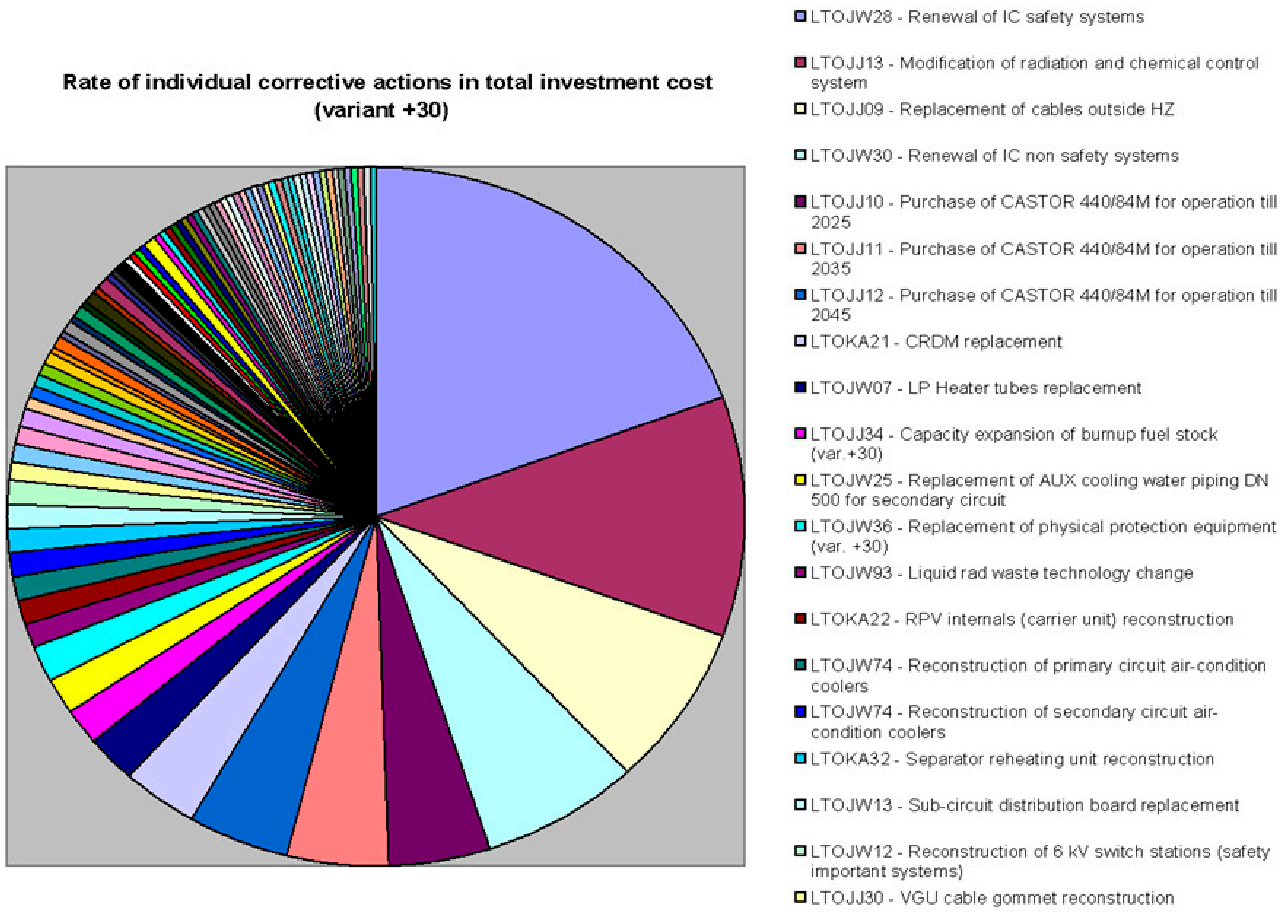


FIG. 22. Rate of individual corrective actions in total investment costs.

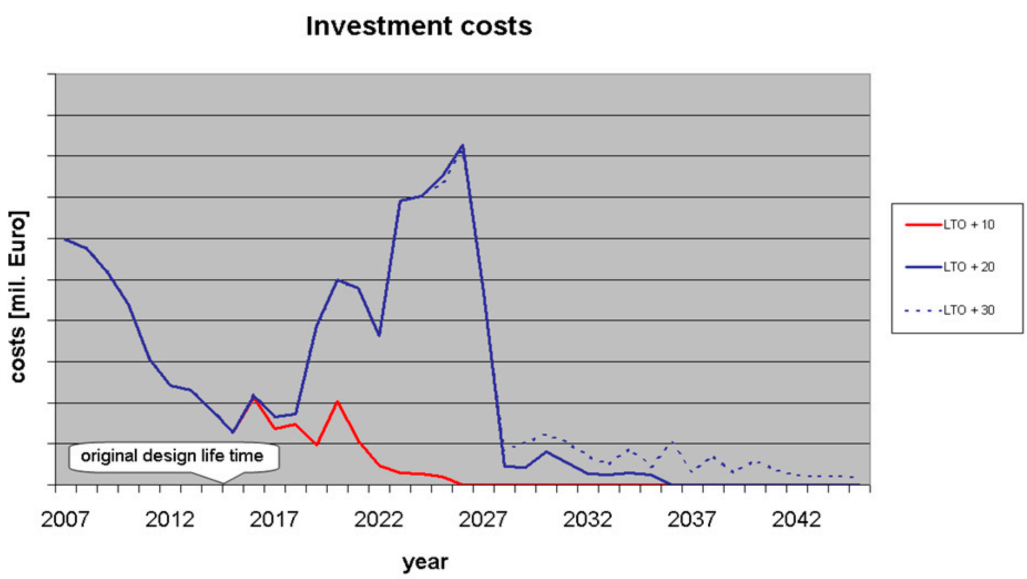


FIG. 23. Technical part of the techno-economic study — investment costs in the timeline for all three LTO options (+10, +20, +30 years).

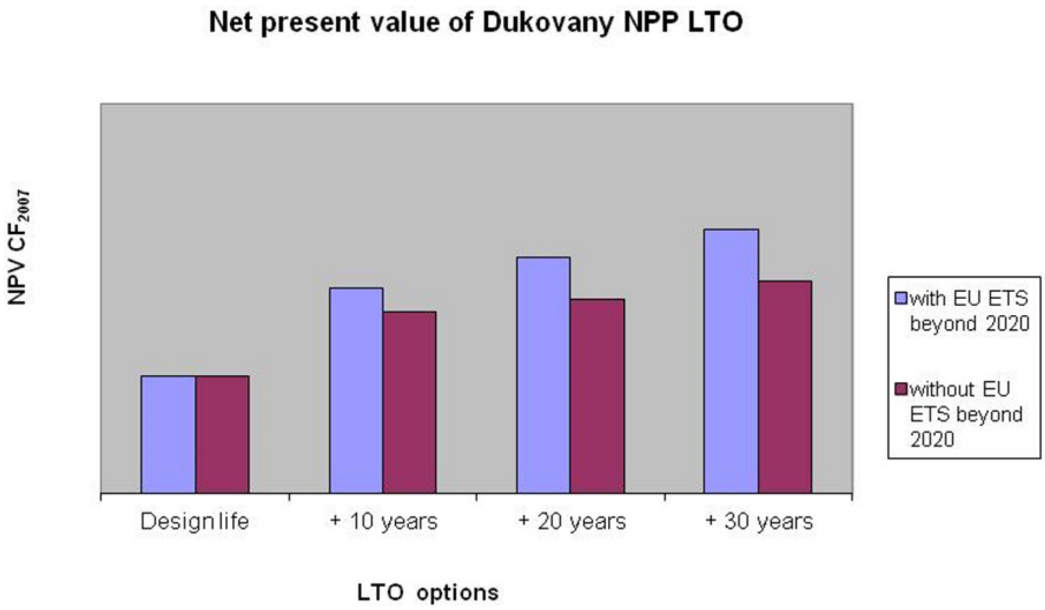


FIG. 24. Economic part of the techno-economic study — NPP NPV at the design life and for all three options (+10, +20, +30 years).

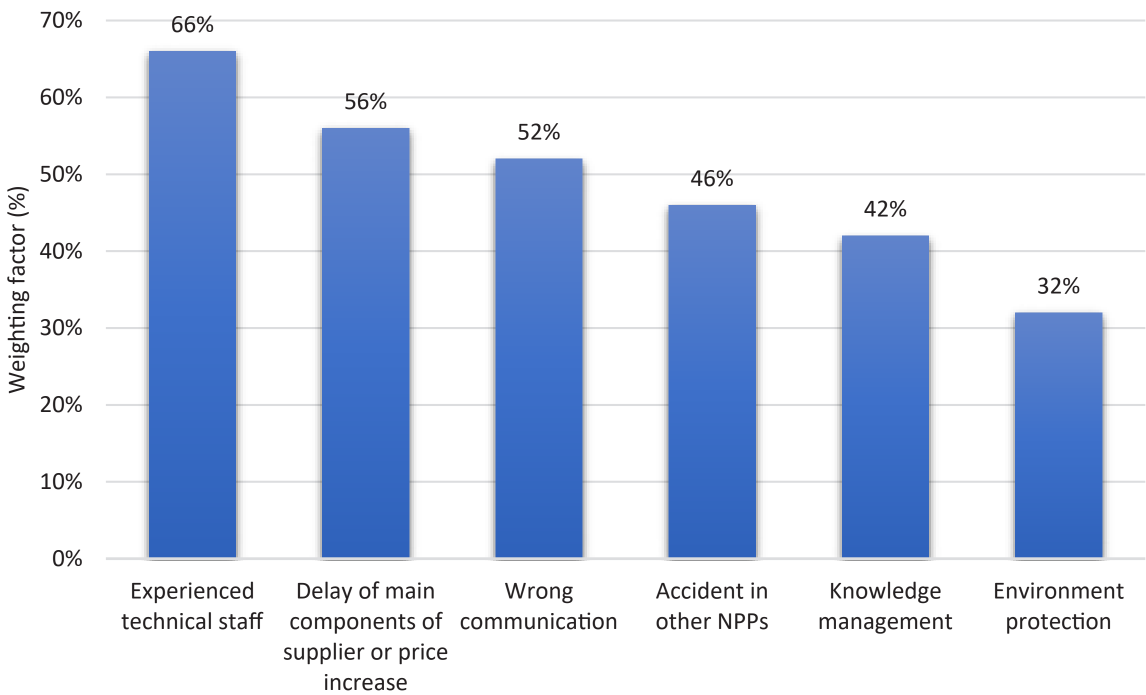


FIG. 25. Results of the risk analysis.

Appendix III

EXAMPLE OF A FEASIBILITY STUDY FOR LONG TERM OPERATION

III.1. STRUCTURE OF A FEASIBILITY STUDY

A feasibility study is composed of several specialized studies that may be conducted for practical reasons in parallel by different expert consultants. The final report should include a detailed summary of the various studies and an integrated assessment to ensure that gaps are not present at the interfaces. For more information on feasibility reports, Ref. [10] can be consulted. For first-time users, a general review may be useful as a first step before embarking on a feasibility study; an IAEA e-learning module [11], with its multimedia examples and hands-on exercises, may be a good starting point. The following topics may be included in a feasibility study, but the list is not exhaustive since local conditions and circumstances may require even more modifications.

— *Overview.* This section should provide a general description of the NPP for which LTO is being considered. It would normally include:
  • The title of the LTO project;
  • The licensee's legal entity;
  • The main reasons for the LTO project;
  • The overall features of the LTO project;
  • The main technical and economic data.
— *Requirements and scoping analysis.* This section may include:
  • The various requirements for the project, including national energy policy, economic development and market prediction at the national and regional levels;
  • An overall LTO project scope;
  • An estimate of the scale of the project in economic terms, but also in terms of stakeholder involvement and of its implications at the industrial, social and environmental levels.
— *Current status of the NPP and its licence basis.* This section may include:
  • Original design basis;
  • Operating performance since the unit started operation;
  • Modifications and enhancement of safety related SSCs during the unit's service life as a result of PSRs and the licensee's own initiatives;
  • Safety enhancement introduced during the unit's service life to meet changing regulatory requirements;
  • Technical and safety status of the unit;
  • Additional safety requirements regarding LTO.
— *Fundamental conditions for an LTO project to be viable, including the results of the site safety assessment and of the environmental impact on its surroundings.* This section may include:
  • Fundamental conditions for LTO to be viable;
  • Conditions favourable for LTO, including national policies, regulatory attitudes, international and domestic practices, the NPP owner's determination and resources and capability of external technical support organizations;
  • Conditions of the NPP site and surroundings, including the changes that occurred during operations such as location and topography, regional cultural and economic conditions, transportation, earthquake and geology, weather and hydrology, and postulated external contrived event.
— *LTO project plan.* This section should cover a preliminary safety assessment, including the main safety and performance features of the LTO project, and a comparison of various LTO models. If it is the first LTO experience in the country, the models can be based on international experience feedback. In any case, the model comparison should result in a recommended configuration. The technical assessment may include:
  • Current status of the NPP unit;
  • Scoping and screening with the short list of SSCs;
  • Preliminary assessment for SSCs after screening;
  • Determination of TLAA items;

- Integrated plant assessment;
- List of SSCs subjected to modification or refurbishment during LTO implementation based on the above integrated plant assessement process with preliminary schemes of individual modification or refurbishment and related preliminary safety evaluation;
- Overall safety assessment for operation with an extended licence;
- Screening results, which may be tabulated in an appendix to the feasibility report;
- Ageing evaluation for safety related SSCs, which may be tabulated in an appendix to the feasibility report.

— *Preliminary evaluation of the environmental impact.* This section contains or refers to a separate EIA, which should include, at a minimum, the following contents:
  - An introductory chapter describing the basis for the EIA, which includes: the site environmental conditions; the enhancements implemented during the plant's service life to maintain or improve its environmental protection features; the environmental analysis requirements; its goals, the methodology and the tools used; the input parameters; the risks considered and the methodology used to assess and quantify them; the assumptions made for the EIA and the evaluation criteria.
  - A chapter analysing the environmental impact of the plant under normal operational conditions.
  - A chapter analysing the environmental impact of the plant under the postulated design basis accident conditions.
  - A chapter describing the environmental risks.
  - A chapter analysing the emergency response and setting the minimum requirements.
  - A chapter analysing the environmental monitoring features required inside and outside the plant perimeter.

— *Occupational safety and hazard, fire protection measures and energy conservation.* This section focuses on occupational safety issues, occupational hazards, fire protection and energy conservation during the implementation phase of LTO, including a general description of the project, the analysis basis, a radioactive and non-radioactive hazard evaluation, measures to uphold industrial hygiene and medical care.

— *Fire control.* This section may contain a fire control system analysis, the applicable codes and standards, an analysis and description of fire control systems, fire detection systems, alarm systems, smoke control and discharge systems, firefighting organizations internal and external to the plant and firefighting stations.

— *Energy conservation features.* This section may include an analysis basis, the applicable codes and standards, an energy supply evaluation and an energy consumption estimate.

— *Organizational structure and training.* This section usually focuses on the organizational structure and the training requirements for the LTO team.

— *Implementation plan.* This section should explain the implementation plan for LTO. It should include the LTO implementation schedule, the resources required and their allocation.

— *BIS outline.* This section may contain the principles and the methodology to be used in the preparation of a BIS and for the bid evaluation. It should include an overview of the domestic and international market analysis, the bid evaluation principles and an outline of the BIS process.

— *Cost estimate and financing structure.* Based on the LTO technical and economic assessments of the previous sections, this part may contain a detailed cost estimate and the required financing structure, with the following information:
  - Estimate basis, with reference to the improvements to SSCs and the requirements resulting from the safety assessment;
  - The work scope, including the engineering cost (nuclear island, conventional island, balance of plant) and the cost of the extended outage, interests, etc.;
  - The estimate methodology;
  - The construction cost;
  - Engineering cost analysis;
  - Financial structure analysis, including the need for capital funds, debt financing and circulating funds.

— *Financial assessment.* This section may include:
  - The principles and basis of the financial assessment;
  - The financial assessment parameters, the cost estimate and the profitability analysis;
  - The uncertainty analysis, including the break-even point and the sensitivity analysis;

- A risk analysis covering the risks involved in the income and cash flow, in engineering activities, in construction, in the schedule and time limits, in financing and operating costs, etc. This section should also include countermeasures against the above risks.

III.2. ECONOMIC ANALYSIS

Economic analysis is a systematic analytical method to determine the optimum use of the available resources. Applied to the electricity market, it involves comparing two or more alternatives to measure, in monetary terms, the private and social costs and benefits of a project to the community and to the economy of a country.

An economic analysis provides insights into how markets operate, and offers methods for attempting to predict future market behaviour in response to events, trends and production cycles. In order to determine the optimal tax rates and evaluate the financial health of the nation or state, governments also use economic analysis.

The economic analysis of an electricity region helps select and design only those projects that contribute to the welfare of a country. Various tools of economic analysis help determine the project's economic and fiscal impact, including its impact on society and on the major stakeholders involved, as well as the related risks and the sustainability of the resources employed.

An economic analysis must be guided by objectives. Once these are established, the most appropriate tools can be selected to conduct the analysis. First, it is important to examine the impact the project will have or the difference it will make to the region. This is an integral part of assessing the incremental costs and benefits of the project. The economic analysis must also examine all possible competing alternatives to the project, identify the costs and benefits of the alternatives and compare them to the project in question. To be comparable, the alternative solutions must be capable of achieving at least the same goals. The economic analysis must ensure that the projects examined are financially sustainable and the risks involved are manageable. The economic analysis should also take into account any external costs, such as the financial impacts of an environmentally sound policy, as well as other social externalities [18, 19].

III.3. DIFFERENT TOOLS FOR ECONOMIC ANALYSIS

Policy makers have a variety of tools for economic analysis at their disposal to help them assess policies and programmes. They are designed to facilitate informed decisions. These tools cover cost analysis, fiscal impact analysis, cost effectiveness analysis and CBA.

The tools used in economic analysis deal with basic managerial and accounting information, but some are also capable of comparing opportunity costs against sunk costs.

An opportunity cost is the cost given up when choosing one method over another. A sunk cost is a cost that is no longer recoverable. An example of a sunk cost could be the cost of equipment to produce goods; once purchased, the money spent is no longer recoverable in economic terms.

The results of an economic analysis conducted using these tools should show all comparative advantages and the ultimate production possibilities.

III.3.1. Types of economic analysis

III.3.1.1. Cost analysis

Cost analysis provides a complete accounting of the expenses related to a given policy or programme decision. It supplies the most basic cost information that both decision makers and practitioners require and forms the foundation for all other economic analyses. However, a cost analysis frequently identifies only the most obvious costs (such as staff salaries) and fails to account for many others.

III.3.1.2. Fiscal impact analysis of a policy or programme

A fiscal impact analysis from a national viewpoint is a comprehensive study of all governmental revenues, expenditures and savings that will result from the proposed policy or programme. State and local fiscal offices routinely produce fiscal impact analyses, which are also called fiscal notes when they are prepared for draft legislation. This type of analysis helps policy makers determine whether a proposed initiative is affordable from a budgetary standpoint.

III.3.1.3. Cost effectiveness analysis

A fiscal impact analysis can help assess how a programme or policy will affect a budget, but it will not reveal whether the programme or policy is an efficient use of resources. There may be less expensive options producing equivalent results. To evaluate which programme or policy creates the expected results at the lowest cost, cost effectiveness analysis should be used.

III.3.1.4. Cost–benefit analysis

CBA is a method for comparing the economic pros and cons of policies and programmes to help policy makers identify the best or most valuable options to pursue. A characteristic feature of CBA is that it monetizes all benefits and costs associated with an initiative so that they can be directly compared. Policies and programmes whose benefits outweigh their costs generate net benefits.

In contrast to cost effectiveness analysis, CBA allows the comparison of initiatives that have different purposes because the outcomes have been monetized. In contrast to fiscal impact analysis, CBA evaluates the costs and benefits of programmes and policies from multiple perspectives, not just that of government agencies.

Costs and benefits are measured over a long term horizon, and future amounts are discounted to reflect the time value of money. The result of a CBA is typically presented as a benefit–cost ratio that indicates the benefit received for every monetary unit invested, providing a bottom line summary of the net benefit to society.

Table 18 shows a simple comparison of the kind of information each type of economic analysis can provide.

In an economic analysis, it is important to identify the costs:

- Direct costs:
  - Staff salary plus fringe benefits (e.g. health insurance, employer's share of social security, workers compensation, unemployment insurance, pension contribution, vacation wages);
  - Equipment, such as computers and office supplies;
  - Rent, occupancy, office maintenance, and other space related costs;
  - Training.
- Indirect costs:
  - Executive staff;
  - Central support (e.g. human resources, fiscal, information technology);
  - Startup and one time costs (e.g. equipment, consultants).
- Future costs:
  - Wage increases, including anticipated collective bargaining settlements;
  - Additional pension contributions;
  - Anticipated health insurance escalation.
- Capital expenses:
  - Project planning, design, development and professional services;
  - Real estate, materials and construction;
  - Contingency;
  - Debt service.

TABLE 18. COMPARISON OF THE VARIOUS TYPES OF ECONOMIC ANALYSIS

Type of economic analysis	Information provided
Cost analysis	Costs of goods and services
Fiscal impact analysis	Impact on the budget
Cost effectiveness analysis	Outputs obtained for the monetary unit
Cost–benefit analysis	How much benefits outweigh costs

Appendix IV

UNCERTAINTIES AND RISK IN ECONOMIC ASSESSMENTS

IV.1. RECOGNITION OF UNCERTAINTY AND RISK IN ECONOMIC ANALYSIS

Risk obviously involves uncertainty. Uncertainty is the set of all outcomes, both favourable and unfavourable. The unfavourable outcomes represent risk, whereas the favourable ones represent opportunity. Thus, uncertainty can give birth to either, or both, risk and opportunity.

Risk is also defined as the probability that an unfavourable outcome will occur. Similarly, opportunity is defined as the probability that a favourable outcome will occur. Uncertainty describes any situation that we do not completely control. Risk describes a situation with a probability of a negative outcome.

There are several types of risk inherent in global energy projects, such as technical, cost, schedule, price, operating factor and political. Accepting risk and providing contingency to cover it is one form of risk control. Other forms of risk control include risk avoidance, risk sharing, risk reduction, risk transfer, insurance and risk containment.

Energy projects have the potential to carry substantial risks and uncertainty. It is important to know how risk and uncertainty could affect expected results from the project and to identify the potential impacts on the investors (owner/operator, investing institutions and government). An analysis of risk and uncertainty will provide key information to allow decision makers to judge whether the project should proceed under the proposed terms. Such an analysis will also assist in negotiations and identification of terms that may mitigate risk or uncertainty for investors. For many energy projects, it is important to have the ability to analyse risk and find ways to best mitigate it, identify potential conflicts of interest and successfully negotiate related issues.

It is recommended that investors incorporate an analysis of risk and uncertainty as part of their overall feasibility analysis of such projects. It is also recommended that investors identify the potential impact from identified risks and uncertainties on expected outcomes. Examples of risks and uncertainties related to projects include [41]:

— Risk and uncertainty associated with the market the project is attempting to capture.
— Risk and uncertainty of investors' revenues from the project.
— Risk and uncertainty associated with the recipient's costs and resource requirements.
— Risk and uncertainty with regard to the recipient's financial and/or credit status. Sometimes a financial guarantee or credit enhancement is required, (e.g. a debt service guarantee).
— Risk and uncertainty that the project will be completed or built, when or as anticipated.
— Risk that other expected outcomes may not occur as anticipated and that investors' goals will not be achieved.
— Risk and uncertainty of future legislative actions and regulatory change by any level of government that may adversely impact a project and its funding.

The chance of a negative outcome is often unknown. By way of example, as shown in Fig. 26, we may be unsure of the true results of a restoration project (uncertainty circle), but there is a risk that the project may not perform as expected (smaller risk circle). The degree of risk may also be uncertain (size of the risk circle). Overall, it is less important to know whether a situation is properly classified as a risk or an uncertainty than it is to ensure that all situations for which the outcome or final result is not known with complete certainty are recognized and dealt with (mitigated) as forthrightly and as effectively as possible during the planning process. The other uncertainties are opportunities. They need only to be estimated and decisions made on where to position the project to draw the maximum benefits.

A risk assessment can provide decision makers with crucial information about:

— The most important factors contributing to uncertainty;
— The contingencies required to obtain a desired level of confidence in a restoration plan;
— The probability of overrunning a project cost estimate and if so, by what percentage;
— The difference of the actual outcome of a project, compared to the original estimate.

FIG. 26. Relationship between risk and uncertainty [42].

Risk and uncertainty are inherent in all projects. They carry with them the potential for time, resource and monetary loss. Identification and measurement of risks must be an integral part of any project development and execution process. Managing risk for mega energy projects is critical in today's competitive business environment.

The analysis of complex decisions with significant uncertainty can be inconclusive if the consequence that will result from selecting any specified alternative cannot be predicted with certainty. Often, a large number of different variables and factors must be taken into account when making the decision. It may be useful to consider the possibility of reducing the uncertainty by collecting additional information. The decision maker's attitude towards risk-taking can influence the objective suitability of different alternatives.

Probabilistic approaches, decision trees, influence diagrams, utility functions, and other decision analysis tools and methods are examples of operations research or methods used in the science of management.

IV.1.1. Real option analysis

Changing energy prices in competitive energy markets, uncertain future carbon prices, uncertain government policy on climate change and the uncertain international regime on climate change mechanisms pose uncertainties to power sector investment. In a process of project investment evaluation, national governments and development banks traditionally use the methodology of discount cash flow. Unfortunately, this methodology cannot fully quantify risks and uncertainties.

Real option analysis (ROA) offers a nuanced approach to strategic investment that quantitatively considers investment risks and the value of the open options for decision makers [43].

A 'real option' is defined as an alternative or choice that becomes available with a business investment opportunity. Real options can include opportunities to expand or cease projects if certain conditions arise. They are referred to as 'real' because they usually pertain to tangible assets such as capital, rather than financial instruments traded as securities (call or put options). Real options can greatly affect the valuation of potential investments.

IV.1.2. Valuation of real options

Often, valuation methods such as NPV do not include the benefits provided by real options. Valuation of real options, often called real options analysis (ROA) or real option valuation, applies option valuation techniques to capital budgeting decisions. A real option itself is the right — but not the obligation — to undertake certain business initiatives, such as deferring, abandoning, expanding, staging or contracting a capital investment project. For example, the opportunity to invest in the expansion of a firm's factory, or alternatively to sell the factory, is a real call or put option, respectively.

Real options are generally distinguished from conventional financial options in the sense that they are not typically traded as securities, and do not usually involve decisions on an underlying asset that is traded as a financial security. A further distinction is that option holders here, i.e. management, can directly influence the value of the option's underlying project, whereas this is not a consideration for the underlying security of a financial option.

Real options analysis, as a discipline, extends from its application in corporate finance to decision making under uncertainty in general, adapting the techniques developed for financial options to 'real-life' decisions. It inevitably forces decision makers to be explicit about the assumptions underlying their projections, and for this reason real option valuation is increasingly employed as a tool in business strategy formulation.

ROA, as comprehensively described in Ref. [44], has been developed over the past two decades specifically for evaluating investments under uncertainty. According to ROA, if an investment is irreversible and the timing of the investment is flexible, the opportunity to invest can be considered a real option. ROA claims that the optimal timing of an investment does not occur until the value of the project itself exceeds the value of the option to invest in the future. In mathematical terms, the real options valuation is based on a stochastic dynamic optimization.

Compared with a traditional static NPV evaluation of expected future cash flows from an investment project, the real options paradigm adds two important analytical dimensions to the problem. First, a dynamic representation of the timing of the investment decision is used. Second, important uncertain factors are represented as stochastic processes. ROA usually yields a more restrictive investment strategy, since the value of waiting for information about uncertain future trends is taken into account. ROA also suggests the use of contingent claims analysis, or risk-neutral valuation, to bypass the problem of determining an appropriate risk adjusted discount rate. The advantage is that a risk free interest rate can be used for discounting. These methods are based on the assumption that a portfolio can be constructed in the financial markets which exactly replicates the uncertainties in the investment project. This is an overextended assumption, since investment projects can involve a number of uncertainties that are not necessarily traded or replicated in financial markets.

Appendix V

CASE STUDIES

V.1. FRANCE: ONGOING DIALOGUE WITH THE SAFETY AUTHORITY

In France, nuclear power licensing is based on the following:

- An initial design life of 40 years;
- No time limit for NPP operation;
- As the plant ages, the safety authority conducts an extensive safety review (PSR) every ten years to ensure that the plant continues to be in conformity with the original safety standards and with any additional requirements;
- Improvements required as a result of the PSR process, of updates to the safety standards, of operating feedback and of lessons learned, must be implemented.

Électricité de France (EDF) has proposed solutions to meet the safety standards and is responsible for implementing them as agreed and approved by the safety authority. The latter is responsible for issuing the authorization to continue operation for ten more years, assuming that the outcome of the PSR is satisfactory and the safety analysis report meets the current licensing requirements.

Most components have been refurbished or replaced after 30 years of operation:

- Steam generators replaced.
- Condensers and heaters replaced.
- Generators: First rewinding of the stators planned before 2020.
- Power transformers refurbished or replaced before 2025.
- Other components examined at the 30th anniversary.

At the time of writing, the third ten year safety review had been completed for 19 reactors. The safety authority found no evidence that EDF was unable to maintain the safety of its 900 MW(e) reactors up to their 40th year of operation.

EDF is looking forward to continued operation of its fleet beyond 40 years. For its part, the safety authority asked EDF to reassess the safety of its reactors under the safety objectives defined for the new generation of reactors.

Following the Fukushima Daiichi accident, EDF embarked, as did other European operators, on a complete reassessment (otherwise referred to as a stress test) of the safety of its NPPs under extreme external stressors and event combinations. These assessments were carried out to complement the existing PSR framework. They revealed that continued operation required strengthening the plants to enable them and their operators to more effectively face extreme external hazards (devastating earthquakes, floods, etc.). The ultimate goal is to limit radioactive releases in the event of a severe reactor accident, and so obtain better assurance that no significant or long term contamination has occurred. Recommendations included:

- Strengthening of water and electricity supplies.
- Improvements in crisis management both in the plants and at the national level.
- Creation of a Nuclear Rapid Response Force (FARN) able to intervene within 24 hours to support operational teams.
- Strengthening of the core protection systems. Some of these protection systems were deemed adequate, such as the system of passive hydrogen recombiners already in place.

The majority of the most critical recommendations have already been implemented or are in process. The safety authority considers that the facilities and their post–Fukushima Daiichi improvement programmes offer a sufficient level of safety.

The total investment in the existing fleet is estimated to be about €55 billion, extending to the end of 2025. This amount is not the cost of service life extensions. Parts of these investments are necessary for safety reasons, even before the plants reach their 40 year mark. It is, however, important to realize that returns on investment would remain negative without the prospect of LTO. The economic benefit will become apparent only when the plants are allowed to operate for 60 years and longer.

The industrial benefits include the following:

— A high level of skills and jobs are maintained;
— Substantial (€55 billion) investments will be made over 15 years to improve and strengthen the fleet;
— EDF will be able to maintain its position as a qualified player for new nuclear power projects.

V.2. ARGENTINA

V.2.1. Nuclear power plants in Argentina

At the time of writing, Argentina operated three NPPs located at two sites: Atucha and Embalse. The three units are at different stages of their operational life.

Atucha I (Central Nuclear Atucha (CNA) I) began operation in 1974. A pressurized heavy water reactor (PHWR) of the pressure vessel type, it was the first NPP in Latin America. Since 2001, it has been fuelled by a mixture of natural and slightly enriched uranium (0.85% of ^{235}U). It has an on-line refuelling system and uses heavy water for cooling and neutron moderation. It generates 357 MW(e) of electricity.

Atucha II (CNA II) is a reactor with similar characteristics and design as CNA I but with some improved safety features. It generates 695 MW(e) of electricity. Construction started in 1981, but was suspended in 1994. The project was resumed in 2006 and first criticality was achieved in June 2014. It has been operating at 100% full power since February 2015.

The Embalse plant, also known as CNE, began operation in 1984. It is a CANDU 6 PHWR fuelled by natural uranium at 0.72% of ^{235}U, and uses heavy water for cooling and neutron moderation. It also has an in-service refuelling system. Embalse generates 648 MW(e) of electricity. In 2010, an agreement was signed to refurbish the plant to extend its operating life by 25 years and increase its power output by about 7%. In Argentina, the nuclear power share of the electricity market before Atucha II was approximately 4.5%.

The share increased to over 6% with full production after Atucha II was connected to the grid. The other energy sources in Argentina are fossil, mainly natural gas (66%) and hydro (28%). Nuclear power generation is a competitive source of energy in the country. The holder of the operating licences and the entity responsible for operating the two Argentine NPPs is Nucleoeléctrica Argentina SA (NA-SA), a state owned company. The regulatory body is the Nuclear Regulatory Authority (Autoridad Regulatoria Nuclear, ARN). The main technical support and R&D organization is the National Atomic Energy Commission (Comisión Nacional de Energía Atómica, CNEA). CNEA is also the organization responsible for nuclear waste management and is one of the partners of a group of associated companies that produce zirconium alloys, fuel bundles, heavy water and uranium dioxide. There are several uranium mining sites in the country managed by CNEA, but they are currently not in operation. Nuclear energy is generally viewed favourably in the country.

V.2.1.1. Regulatory approach

In the early operating stages of the NPPs, plant ageing was managed by inspection. In 1998, ARN issued a regulatory requirement to the effect that CNA I and CNE should implement an AMP, which formalized the ageing management requirement of important components by optimizing the inspection and maintenance programmes, and by applying monitoring, prevention and mitigation of ageing effects.

In 2003, ARN decided to modify the operating licence officially granted to the licensee (NA-SA) for CNA I to incorporate the aforementioned regulatory requirement on plant ageing management and a set of new requirements related to radiological and nuclear safety, safeguards and physical protection of the facilities. In 2007, the operating licence granted to CNE was modified to include ageing management and additional radiological protection and nuclear safety requirements. Following the same criteria, ARN established the regulatory framework for the licensing process of CNA II, establishing the AMP as mandatory.

The operating licence of the Argentine NPPs is valid for ten years from the date of issue. In addition, the operating licence stipulates that a PSR is a necessary condition for renewal. During a PSR, the safety related aspects of the installation are reviewed to a degree equivalent to the one indicated in IAEA Safety Standards Series No. SSG-25, Periodic Safety Review for Nuclear Power Plants [5], which involves an analysis of 14 safety factors among which is plant ageing.

ARN monitors AMPs through regulatory inspections, evaluations and audits during normal operation and scheduled outages. ARN also assesses the test results of in-service inspections, preventive maintenance programmes and periodic reports submitted in accordance with the requirements of the operating licence. The following mandatory high level requirements are listed in the Argentine regulatory standards related to general ageing requirements:

— Nuclear Power Plant Quality Systems, AR 3.6.1;
— General Safety Criteria in the Design of Nuclear Power Plants, AR 3.2.1;
— General Safety Criteria for the Operation of Nuclear Power Plants, AR 3.9.1.

In addition, a range of IAEA Safety Standards, Safety Guides, Nuclear Energy Series and other publications as well as Canadian Nuclear Safety Commission standards are used as guidance.

Within the framework of the PSR process, the AMPs of the Atucha and Embalse NPPs are being updated to modern standards and practices.

V.2.1.2. Ageing management and long term operation

Embalse NPP. In CANDU 6 type reactors, service life is divided into two periods of 30 full power years each, with a major refurbishment in between. Fuel channel creep caused by irradiation limits the service life of the reactor core, which consists of a group of tubular fuel channels. At the end of the first 30 years of operation, a fuel channel replacement campaign, in parallel with the refurbishment of other SSCs, is required to obtain authorization for a second operating period. In 2007, NA-SA started an extensive ageing management review (AMR) of CNE as the first step towards fuel channel replacement and the plant refurbishment process. The refurbishment project was organized in three phases:

— Phase 1 included ageing assessments, safety assessments and economic assessments;
— Phase 2 included project engineering and preparatory steps in the field;
— Phase 3 was dedicated to project implementation.

The refurbishment process of a CANDU reactor involves the replacement of major components, such as pressure tubes, calandria tubes, feeders, the main control computer, steam generator tubes and other structures and components important for safety. The engineering tasks for this process are currently ongoing and the refurbishment outage will be completed at the end of 2018. According to publicly released information, the overall cost of the project was estimated to be $1800–2000/kW(e).

Atucha I NPP. In 2010, NA-SA established a specific group to deal with the ageing management of both the CNA I and CNA II NPPs. In addition, an AMR was initiated for Atucha I. This process is ongoing and is part of the feasibility study framework for Atucha I’s life extension. Some modernization and improvements have already been completed. Others are in the process of being incorporated. They are:

— Installation of a secondary heat sink;
— Addition of new dry storage facilities (under construction);
— Addition of a new engineering protection system;
— Equipment qualification and seismic qualification upgrades;
— Installation of hydrogen recombiners.

V.3. CHINA

China initiated nuclear power operation in 1991 when its first NPP unit, Qinshan 1, a 300 MW(e) PWR, was connected to the grid. As of 31 March 2015, China had 26 units connected to the grid, 23 of which were in commercial operation. The age distribution of the 23 units in commercial operation is as follows: 20 units operating for less than 20 years, 3 units between 20 and 30 years.

The main source of electricity in China is thermal power (of which 90% is from coal), which contributed 75.25% of electricity production in 2014. The nuclear power share of electricity production is only about 2.28%. However, the nuclear share is slowly rising as new NPP units come on stream.

At the time of writing, most nuclear and conventional power plants in China are located along the eastern coastal areas, close to the large electricity users. Coal fired plants remain the main source of baseload electricity production in China. They also cause air quality issues and are handicapped by the distant location of the coal mines in the country's interior, which adds transportation cost to the final cost of electricity from these plants. In this context, increasing the nuclear power share in China is seen as an attractive alternative to coal fired solutions. Even more economically attractive, compared with both new NPPs and new coal fired plants, are LTO solutions. In general, cost–benefit studies in China have shown that both LTO of existing NPPs as well as new NPP builds continue to be primary contenders in all Chinese electricity system scenarios.

In China, the duration of operating life is based on the initial NPP design lifetime. The design lifetime of Qinshan 1 is 30 years, and for other units in commercial operation it is 40 years. Third generation units (AP1000, EPR) under construction have a 60 year design life. Currently, regulatory requirements for operating licence extensions (OLEs) are being developed. The licence renewal/management process for NPPs in China is similar to the process in the USA. Although PSRs are required during operation, regulatory requirements for OLE will include items from both the PSR and the US licence renewal system.

Qinshan 1, the oldest NPP unit in China, has been operating safely for 24 years, and its original licence expires at its 30th year of operation. OLE activities have been undertaken to extend operation of the plant for 20 years beyond its original licence limit. The main OLE activities are as follows.

The NPP operator carries out a detailed feasibility study comprising a wide range of considerations, including:

- National energy policies;
- NPP owner/operator goals and strategies;
- Actual status of the NPP unit;
- Current licence basis;
- Preliminary safety assessment;
- Preliminary EIA;
- Overall scheme of the OLE project;
- Investment assessment;
- Financial analysis, etc.

The feasibility assessment report is submitted to the NPP owner for approval. Once the OLE project is approved, the NPP operator formulates a detailed OLE work plan, which includes the OLE model, implementation strategies and an effectiveness assessment of the current licensing basis. The owner allocates responsibilities, issues the organizational structure, identifies internal and external resources, develops the schedule and attaches a list of supporting documents to the OLE application. The working plan is then submitted to the nuclear safety regulatory body for approval.

Once the nuclear safety regulator approves the work plan, an OLE application report along with a series of supporting documents is submitted to the nuclear safety regulator for review. After reviewing the application for a period of five years at the most, approval is given and a series of SSC improvements, modifications and refurbishments is carried out and completed before the original licence expires. The nuclear safety regulator issues OLEs for a maximum of 20 years.

V.4. CZECH REPUBLIC

At the time of writing, there were two NPPs in operation in the Czech Republic: Dukovany and Temelín. Dukovany has four WWER-440/213 units of Russian design which were commissioned between 1985 and 1987. Temelín has two WWER-1000/V320 units, also of Russian design, which were commissioned between 2000 and 2002. The four Dukovany units have been in operation for 20–30 years, while the two Temelín units have been operating for less than 20 years.

The share of nuclear power generation in the Czech Republic is currently about 40% of total electricity output. In the national energy strategy, this share is supposed to increase to 50% after 2040. The share of hydropower in total electricity production is about 1%. Electricity production from solar, biomass and wind power is subsidized. Therefore, only nuclear, coal and gas plants can be compared. The production cost of electricity from gas power plants is higher than the market price. This is the reason that a newly constructed gas plant was never started. The electricity production cost from the Dukovany NPP is about 35% lower than the lowest cost from coal plants. In the case of Temelín, it is about 10% lower.

The design lifetime of both NPPs is 30 years, which was originally based on the lifetime of the main components, such as steam generators, reactor coolant pumps and pressurizers. The design lifetime of the reactor pressure vessels is 40 years. The operating licence is unlimited in the Czech Republic, but the national regulator — the State Office for Nuclear Safety (SONS) — requires a safety review of the NPPs every ten years and can authorize continued operation of an NPP for another ten years based on:

— The PSR results;
— The updated FSAR;
— The completion of all improvements required in previous SONS reviews.

Additional SONS requirements, based on recommendations from the IAEA's Safety Aspects of Long Term Operation (SALTO) missions, have to be met for operational authorizations beyond the NPP design lifetime. They include:

— Scoping, screening, AMR;
— Revalidation of the TLAA;
— Launch of an integrated AMP.

At the time of writing, the LTO authorization process for Dukovany Unit 1 was in progress. While this process is not fully described in the regulations, the utility (ČEZ) has to submit to SONS the documents required in the Atomic Energy Act. The main document is a request for authorization to operate a nuclear installation, which contains the following:

— The documents necessary to obtain a ten year operational authorization;
— A document demonstrating the equipment and personnel readiness for LTO (including such SALTO activities as scoping, screening, AMR, TLAA);
— An international independent verification of LTO readiness.

The applicant was required to submit these documents to SONS no later than 90 days before the end of the operating term, which expired on 31 December 2015 for Dukovany Unit 1.

The SSC refurbishments of the Dukovany NPP connected to the LTO application started in 1998 with Project MORAVA. Safety enhancements, including seismic qualification reviews of equipment, piping and instruments, were carried out in this project. Between 2005 and 2012, a power uprate project was also initiated. The unit capacity went from 440 MW(e) to 500 MW(e). The low and high pressure turbine rotors and the high pressure heaters were replaced, the generator rotor windings were re-isolated and the generator stators were replaced, as were the core and the winding of the output transformers. Since 2003, an I&C replacement project to upgrade the safety systems, the turbine, the reactor and key auxiliary systems is being implemented. The following upgrades have been carried out:

— Seismic enhancement of the main technology buildings;

— Replacement of fire protection and electrical systems;
— Construction of an ultimate heat sink;
— Capacity upgrade of the passive autocatalytic hydrogen recombiners;
— Addition of an external reactor vessel cooling system to mitigate severe accidents (corium in vessel retention);
— In subsequent years, the control rod drives and some parts of the I&C and electrical systems.

In connection with safety enhancements after the Fukushima Daiichi accident, new station blackout diesel generators (SBO-DGs) (resistant to seismic and other external natural hazards), mobile generators, an additional third division of the emergency feedwater pump system connectable to the SBO-DGs, and provisions for a backup coolant supply to the depressurized reactor and spent fuel pool were installed. New emergency procedures for extreme external events were developed. Existing severe accident management guidelines (SAMGs) were updated to cover new emergency strategies, supplemented by new extensive damage mitigation guidelines and shutdown SAMGs. Currently, activities comprising increased resistance of some of the main technology buildings against external natural hazards and extending the post-accident monitoring systems are being implemented.

In addition, the following activities connected with LTO were performed:

— Scoping, screening, AMR;
— Enhancement of existing or development of new AMPs;
— Revalidation of TLAAs;
— Research in the area of ageing management and TLAA (for example, environmental assisted fatigue material research);
— Implementation of a knowledge management programme for LTO.

The total LTO costs, including the costs of the above mentioned activities, and of those related to the post–Fukushima Daiichi enhancements, as imposed by SONS for the issuance of an LTO authorization amount to about $900/kW(e).

Public opinion in the Czech Republic supports nuclear energy and LTO. The last public opinion polls in 2013 and 2014 showed that 68% of the population supported nuclear energy. This number grows to 74% locally near Dukovany and 72% near Temelín. Half of the population of the Czech Republic supports extending operation of the Dukovany NPP to 60 years (30 years beyond its design lifetime). In addition, 35% supports 40–50 years of operation (10–20 years beyond the design lifetime), while the remainder supports decommissioning as soon as possible.

ČEZ is developing a technical and economic feasibility study for Dukovany that envisages 50–60 years of operation (the second and third LTO operational authorization renewal period).

V.5. UNITED STATES OF AMERICA

An example from the USA of the evaluation and implementation process for LTO is the Vermont Yankee NPP. The plant began operation in 1972, when the NRC issued a 40 year operating licence. In 2002, the plant was purchased by Entergy Nuclear and was being operated in a ‘merchant’ (or liberalized) market for electricity. At that time, the plant had operated for 30 years. The purchase deal included a ten year wholesale power purchase agreement that helped ensure a reasonable financial situation until 2012.

In 2004, based on the economics of LTO where Vermont Yankee was located, it was determined that the cost of a licence renewal project to obtain the option of 60 years of operation was justified. The nuclear plant had been well maintained and no major equipment replacement or refurbishment was required to ensure safe and reliable operation for up to 60 years, as per the LRA [44]. For example, from 2003 to 2006, the plant implemented plant upgrades to support a 20% power uprate, which helped further improve the economics of LTO. This meant more megawatts for approximately the same annual O&M costs. The upgrade also improved the material condition of significant portions of the plant (i.e. secondary system upgrades and replacements needed to allow 20% higher power levels).

In 2011, the NRC granted a licence authorizing Vermont Yankee to operate for up to 60 years as long as the safety and environmental conditions of the licence were maintained. In 2012, the plant reached the 40 year milestone and was successfully operating beyond the original licence term (i.e. the period of extended operation) and was supplying more than 70% of the electricity generated in Vermont.

However, by 2013 the economic situation had changed due to several factors. The ten year power purchase agreement expired in 2012 and Entergy was unable to negotiate a new agreement for a long term wholesale price that would support continued operation. This was due to low energy prices in the region resulting from increased shale gas production. In addition, the plant was experiencing higher operating costs due in part to new regulatory requirements, such as NRC mandated Fukushima Daiichi response action items and legal challenges to continued operation. Due to this combination of lower energy prices and higher operating costs, Entergy announced in early 2014 that the Vermont Yankee nuclear plant would be permanently shut down by the end of 2014 (i.e. after more than 42.5 years of operation) and then decommissioned. This situation is an example of external changes (e.g. the market price of power) and unpredictable circumstances (e.g. the Fukushima Daiichi accident) that can occur as a plant ages, resulting in a reversal of an earlier decision for LTO.

V.6. BRAZIL

At the time of writing, Brazil had two NPPs in operation, Angra 1 and Angra 2, contributing 2% of the total installed capacity in the country. The main source of electricity generation is hydropower. A third NPP, Angra 3, was suspended due to limitations of Eletronuclear's cash flow as of 2017.

In addition to the environmental licensing process and the required public hearings, the NPP operating licence process of the Brazilian National Nuclear Energy Commission (Comissão Nacional de Energia Nuclear, CNEN) consists of:

— The site approval process;
— The construction licence;
— The authorization for the use of nuclear material;
— The authorization for initial operation;
— The authorization for permanent operation.

The first operating licence is issued for a period of 40 years, but must be revalidated every ten years, through a PSR, for the next ten years.

The oldest Brazilian NPP (Angra 1) started commercial operation in January 1985 using the Authorization for Initial Operation. In September 2010, CNEN ratified operation of the plant until 2024 through an announcement in the Brazilian Government Gazette.

In order to achieve this goal, Eletronuclear has since 2010 been implementing an integrated AMP for Angra 1, an essential element to support the plant's service life extension and to secure the renewal of the operating licence. This was done in parallel with all routine maintenance activities aimed at keeping Angra 1 at a high level of operational performance and at ensuring the safety of all its operational processes.

The AMP covers management of the physical and technological ageing (obsolescence) of SSCs relevant to the operational safety of the plant; the effects of ageing are monitored and remedied when necessary. Components and structures that show signs of degradation are identified and replaced. This AMP will be complemented by a four year plant diagnosis project, the integrated plant assessment.

Following global trends [44], Eletronuclear will request licence renewal for an additional period of 20 years, which will allow continuing operation of Angra 1 to 2044.

Since the designer of Angra 1 is the US company Westinghouse and US standards are consistent with the requirements set out by the IAEA, Eletronuclear proposed to CNEN the adoption of US regulations as a reference for the operating licence renewal process for Angra 1. Specifically, the licensing process for life extension will follow the NRC's 10 CFR Part 54 [44], which defines the rules for the licence renewal process of NPPs in the USA. Examples of other US standards that will be used are NUREG-1800 [45], NUREG-1801 [46], Regulatory Guide 1188 [47] and NEI 95-10 [48].

The integrated plant assessment and implementation of the resulting improvements and recommendations were completed five years before the expiration of the current licence. In 2019, Eletronuclear plans to formalize the application for the renewal of Angra 1's operating licence. This will provide CNEN with enough time (five years) to complete its evaluation.

In addition to the two major investments required for Angra 1's life extension that have already been made (the steam generator replacement in 2009 and the reactor pressure vessel closure head (RPVH) replacement in 2013), Eletronuclear will invest approximately $430–470 million between 2015 and 2019 to:

— Maintain the design's safety and performance levels;
— Implement a power uprate programme and a project to reduce the duration of outages;
— Implement the Angra 1 LTO project;
— Incorporate the Fukushima Daiichi accident response plan;
— Build a waste management monitoring centre and a spent fuel supplementary storage unit.

Angra 1 shows an investment per kW(e) in LTO of 2015 $670–720/kW(e) if replacement of the steam generator and RPVH is excluded, and of $1030–1090/kW(e) if the replacement of both components is included.

V.7. RUSSIAN FEDERATION

In the Russian Federation, there are ten operating NPPs, and the number of reactor units operating within these plants is 37. Figure 27 shows the age distribution by number of operating years of the nuclear power generating units in the Russian Federation.

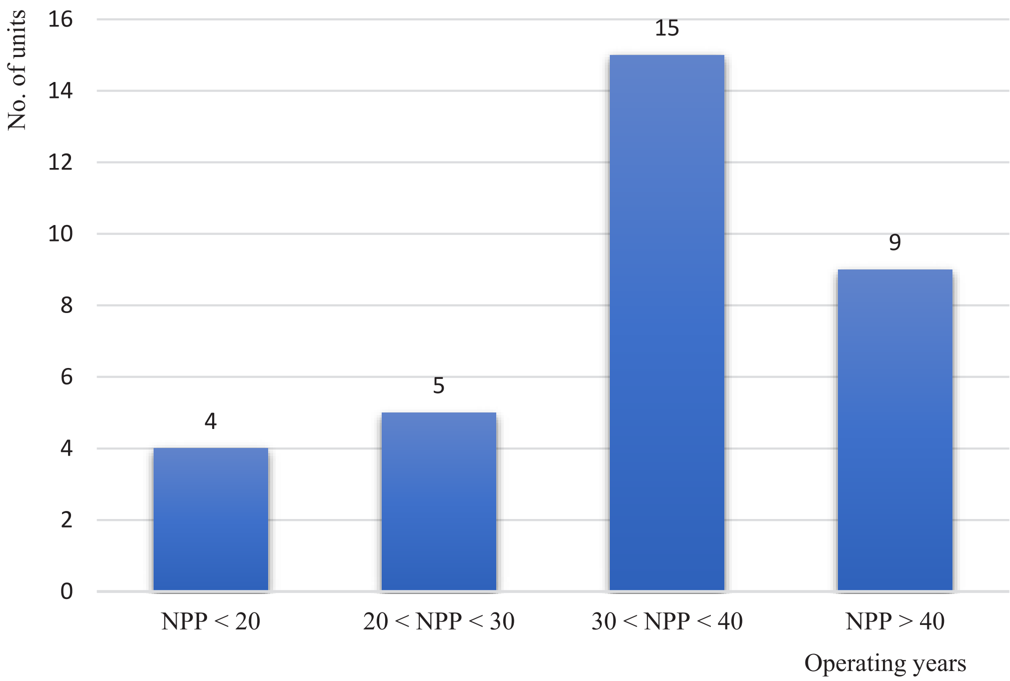


FIG. 27. Age distribution of the reactor units in the Russian Federation.

The nuclear power share of electricity production, as an average trend, is about 16%. The cost of electricity produced from NPPs is 1.0416 roubles per kW·h, equivalent to $0.018 per kW·h. Information about the cost of electricity produced by other types of power plants is not available.

V.7.1. Legislation for long term operation

The design lifetime of the Russian units by reactor type is as follows:

— BN-600[10]: 30 years.
— RBMK-1000[11]: 30 years.
— EGP-6[12]: 30 years.
— WWER-440: 30 years.
— WWER-1000: 30 years.
— WWER-1200: 60 years.

The operating licence time limit is the same as the reactor design lifetime. The Russian Federation has adopted the PSR approach to check the influence of ageing on reactor safety and to authorize continued operation. The period between safety reviews is ten years. LTO of the Russian plants beyond their design lifetime is allowed on the condition that the safety improvements required by the Russian Government and the IAEA have been implemented, as agreed with the nuclear safety authority.

A licence extension for Russian reactors is granted per reactor type as follows:

— *BN-600.* The first OLE for these units is limited to 15 years. Beyond this term, at this point in time, these units are expected to receive another licence extension of 15 years.
— *RBMK-1000.* These units have been granted an extension of 15 years beyond their initial design lifetime. A further extension of their operating licence is currently not foreseen. They are slated to be decommissioned.
— *EGP-6.* These units have been granted an OLE of 15 years beyond their original design lifetime.
— *WWER-440.* These units have been granted an extension of 15 years beyond their initial design lifetime. A further extension of their operating licence will depend on the condition of each unit and an economic analysis of the region where they are located. It is expected that some units will be granted further extensions, while others will be decommissioned.
— *WWER-1000.* These units are being granted an extension of their operating extension of either 25 or 30 years.
— *WWER-1200.* These units are of a newer generation design. Their expected service life is 60 years. Life extensions have not yet been set.

The extension application and approval process includes the following main steps:

— A comprehensive inspection and safety assessment.
— The preparation of the NPP extended service life investment project.
— The implementation of modernization projects and of AMPs during the original operating licence period to prepare the unit for the licence extension project.
— The development of the nuclear and environmental licensing framework.
— Communication with the public carried out through the public information centres of the NPP.
— Preparation of the main technical content of the LTO licensing documentation (e.g. scope of ageing management, evaluation of the condition of the SSCs, equipment qualification, TLAA).
— Presentation of substantiating materials to the federal environmental, industrial and nuclear supervision service (Rostechnadzor) to obtain a licence extension to operate the NPP.

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[10] BN-600 is a sodium cooled fast breeder reactor generating approximately 600 MW.

[11] RBMK is a graphite moderated pressure tube reactor. Nine RBMKs under construction were cancelled after the Chernobyl disaster. The remaining RBMKs at Chernobyl were shut down in 2000. There are 11 RBMK reactors operating in the Russian Federation. They have all been retrofitted with safety improvements.

[12] EGP-6 is a scaled down version of the RBMK reactor design. It is the smallest power reactor in the world. Four units, producing a total of 48 MW, are operating in Bilibino, northwestern Siberia.

— Implementation of the most significant items of reconstruction and replacement connected to LTO (reactor island, turbine island, electric equipment, I&C, etc.). This work includes:
  - Annealing of vessel WWER-1000;
  - Replacement of the fuel channels in the reactor core of RBMK-1000 plants;
  - Repair of the graphite blocks in the reactor core of RBMK-1000 plants;
  - Replacement of steam generators;
  - Refurbishment of the main circulation pumps;
  - Replacement of the heat exchangers of the secondary circuit;
  - Replacement of the turbine condensers;
  - Replacement of containment penetrations;
  - Modernization of the reactor main control room.

A comprehensive modernization of the RBMK-1000 NPP was completed after the Chernobyl accident.

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Annex

CONCEPTS

A–1. PURCHASING POWER OF MONEY

The purchasing power of money is the amount of goods or services that one unit of money can buy. It declines over time because of (price) inflation, which is an economic condition causing an increase in the price of goods and services over time. The opposite phenomenon, called deflation, can also occur, causing a decline in prices.

Inflation is measured through the gross domestic product (GDP) deflator, the consumer price index (CPI), the producer price index and the wholesale price index. CPI, a commonly used measure of inflation, is calculated and reported yearly by the country's labour or statistics department or the monetary authority. The authority establishes a base year and sets the index as 100 for that year, after which it measures the changes in purchasing power in a particular year and adjusts this index accordingly. When the CPI declines, the purchasing power rises.

While carrying out an economic analysis, it is necessary to fix the purchasing power of the currency used for the analysis, for a selected year 't', called the base year (for example, the year 2010). The purchasing power of that currency at any given year 'z' can be transformed in terms of its purchasing power in the base year 't'.

With the CPI as the inflation index, divide the CPI of the base year by the CPI of the target year and then multiply the result by the price or cost to obtain its equivalent value in the target year.

A–2. TIME VALUE OF MONEY

The time value of money refers to the fact that a dollar today is worth more than a dollar promised at some future time. Some maintain that this concept arose because the money available now can be invested to earn interest; thus, a dollar today would grow to more than one into the future and this might result in an injection of capital into the market. The reality is that money made available in the future must be discounted by an appropriate factor to arrive at its present value. The conceptual understanding of the time value of money is essential for an economic/financial analysis. The time value of money leads to the concept of present value (*PV*) and future value (*FV*). If a dollar today earns interest at rate r, it becomes $1 + r$ one year from now. Therefore, turning this around, the *PV* of $1 + r$ dollars received one year from now is 1. Hence, the *PV* of 1 dollar received one year from now is:

$$PV = \frac{1}{(1+r)}$$

Applying the same method, a dollar today, if invested at an interest rate of r, becomes $(1 + r)^n$, where n is the number of years from now. Thus, the *PV* of 1 dollar received n years from now is:

$$PV = \frac{1}{(1+r)^n}$$

If r is the interest rate, then an amount X received after n years has a *PV*, which could be calculated with the following formula:

$$PV(X) = \frac{X}{(1+r)^n}$$

Because the possibility of earning interest reduces the *PV* below the amount X, the process of finding a *PV* of a future sum of money is called 'discounting'. The formula shows precisely how much future sums should be discounted. The factor $\frac{1}{(1+r)^n}$ is called the 'discount factor'.

A–3. COSTS (PRIVATE, EXTERNAL AND SOCIAL)

Private cost is a producer's cost of providing goods or services. It includes the costs the firm pays to purchase capital equipment, hire labour and buy materials or other inputs, but excludes external costs incurred as environmental damage (unless the producer or supplier is liable to pay for them). Private costs are paid by the firm or consumer and included in production and consumption decisions. In a competitive market, considering only the private costs will lead to an efficient rate of output only if there are no external costs.

External costs are costs not reflected on the firm's income statements or in consumer decisions. However, external costs remain costs to society regardless of who pays for them. Consider a firm that attempts to save money by not installing water pollution control equipment. Because of the firm's actions, cities located down river will have to pay to clean the water before it is fit for drinking, the public may find that recreational use of the river is restricted, and the fishing industry may be harmed.

Social costs include both the private costs and any other external costs to society arising from the production or consumption of a good or service. When external costs are paid, they must be added to private costs to determine social costs and to ensure that a socially efficient rate of output is generated.

A–4. DISCOUNT RATE

In economic and financial decision making, to correct the time value aspects of money, the future cash flow needs to be discounted to convert it to 'present value' so that it becomes comparable to the current monetary value. The choice of discount rate depends on the purpose of discounting. In an economic analysis, the appropriate discount may be the opportunity cost of capital. In a financial analysis, when evaluating the project as a whole, the cost of capital, which is the firm's/project's weighted average cost of debt and of its equity capital, may be the appropriate discount rate. However, for equity investors, who are providing equity capital, their required return on the equity should be used to discount the cash flow; the cash flow adds value to their investment.

A–5. DEPRECIATION

In accounting, depreciation refers to two aspects of the same concept [A–1]:

— The decrease in value of assets because of ageing;
— The allocation of the cost of assets to periods in which the assets are used (depreciation with the matching principle).

The former affects the balance sheet of a business or entity, while the latter affects the net income that they report. In the income statement, the cost of using an asset is allocated as a depreciation expense through the periods in which the asset is expected to be used. This expense is recognized by businesses for financial reporting and tax purposes. Methods of computing depreciation, and the periods over which assets depreciate, may vary between asset types within the same business and for tax purposes. These may be specified by law or accounting standards, which vary by country. There are several standard methods of computing depreciation expense, including the fixed percentage, straight line and declining balance methods. Depreciation expense generally begins when the asset is placed into service.

Most income tax systems allow a tax deduction to recover the cost of assets used in a business, or to produce income. Such deductions are allowed for individuals and companies. Where the assets are consumed currently, the cost may be deducted currently as an expense or treated as part of the cost of goods sold. The cost of assets not currently consumed generally must be deferred and recovered over time, such as through depreciation. Some systems permit full deduction of the cost, at least in part, in the year the assets are acquired. Other systems allow depreciation expense over a specified lifetime using a depreciation method or percentage. Rules vary by country, and may vary within a country based on the type of asset or on the taxpayer bracket.

A–6. TAXES

A tax is a financial charge or levy imposed upon an individual or legal entity by a State or the functional equivalent of a State. The electricity sector at its different stages is subject to various forms of taxation (corporate tax, value added tax, sales tax, etc.). The energy industry in general is subject to many taxes and duties, corporate taxes, VAT, etc. Taxes can be one of the largest cash outflows for a firm. The size of a firm's tax bill is determined by the tax code and rules, both of which vary from country to country.

A–7. LEVELIZED UNIT ELECTRICITY COST

The levelized cost of electricity (LCOE) is a helpful tool for comparing the unit costs of different technologies over their economic life. Electricity must be generated over the lifetime of the project to make the investment break even at this price. The following formula is used by the International Energy Agency (IEA) and the Nuclear Energy Agency of the Organisation for Economic Co-operation and Development (OECD/NEA) to compute LCOE:

$$\mathrm{LCOE} = \mathrm{P}_{\mathrm{Elec}} = \frac{\sum_t \left(\left(\mathrm{Investment}_t + \mathrm{O\,\&\,M}_t + \mathrm{Fuel}_t + \mathrm{Carbon}_t + \mathrm{Decommissioning}_t \right) \times (1+r)^{-t} \right)}{\sum_t \left(\mathrm{Electricity}_t \times (1+r)^{-t} \right)}$$

This methodology nevertheless concentrates on the cost at the production level. For certain technologies, there may be significant costs at the level of the electricity system over and above the plant level production costs. To ensure balance between demand and supply in electricity systems with a significant share of variable renewables, the electricity system needs short term reserves and long term capacity provided by power generators such as nuclear, coal or gas. According to an OECD/NEA study [A–2], renewables such as wind and solar, because of their intermittent nature, generate system effects that are at least an order of magnitude greater than those caused by technologies such as nuclear, coal or gas. Therefore, making a decision on technology choices based only on plant level costs, while ignoring grid and system level costs, would lead to the selection of technologies that may not be optimal when considering the system as a whole.

A–8. NET PRESENT VALUE

Net present value (NPV) is the difference between the present values of cash inflows and cash outflows. It is a widely used indicator to analyse the profitability of an investment or project. The NPV is a measure of how much value is created or added today by undertaking an investment.

If R_t and C_t are, respectively, the revenue and cost streams of a project over its lifetime, *n,* and *r* is the discount rate, then NPV is calculated with this formula:

$$NPV = \sum_{t=0}^{N} \frac{(R_t - C_t)}{(1+r)^t}$$

For the project evaluation, the NPV criteria are listed in Table A–1.

A project is acceptable if the NPV is positive and rejected if it is negative. In the unlikely event that it is zero, this indicates that the investment/project neither loses nor gains value. In addition, the NPV is sensitive to the discount rate used, declining with increasing discount rates. Therefore, making appropriate choices with respect to the discount rate is important when evaluating a project using NPV as an indicator.

TABLE A–1. PROJECT EVALUATION: NPV CRITERIA

If	It means	Then
NPV > 0	The investment would add value to the firm	The project may be accepted
NPV < 0	The investment would cause the firm to lose value	The project may be rejected
NPV = 0	The project neither loses or gains value for the firm	

A–9. OTHER ECONOMIC INDICATORS

The internal rate of return, or IRR, is the average annual return earned through the life of an investment. This discount rate makes the NPV of all cash flows from a particular project equal to zero. It is therefore calculated with this formula:

$$\sum_{t=1}^{N} \frac{R_t - C_t}{(1+r)^t} = 0$$

where r is the discount rate at which the NPV of the project becomes zero, also called IRR.

An investment is acceptable if the IRR exceeds the required return. Otherwise, it should be rejected. The required return can be the cost of capital or return on equity (ROE) or a minimum return accepted by a firm or by the investor.

A benefit–cost ratio (BCR) is an indicator, used in cost–benefit analysis (CBA), that attempts to summarize the overall value of a project or proposal in monetary terms. A BCR is the ratio of the *PV* of the benefits of a project or proposal and its costs expressed in monetary terms. If a project has a positive NPV, then the *PV* of the future cash flows must be larger than the costs. The BCR thus would be greater than 1 for a positive NPV investment and less than 1 for a negative NPV investment. If B_t and C_t are, respectively, the stream of benefits and costs of a project, and r is the discount rate, then the BCR can be calculated using this formula:

$$BCR = \frac{\sum_{t=0}^{N} \frac{B_t}{(1+r)^t}}{\sum_{t=0}^{N} \frac{C_t}{(1+r)^t}}$$

The BCR measures the value created per dollar of cost. The higher the BCR, the better the investment. Like the NPV, the BCR is sensitive to the choice of the discount rate. At a certain discount rate, the project may be considered acceptable, but at some other discount rate it may not. The selection process for the discount rates can be the same as that used in the NPV.

A–10. FINANCIAL INDICATORS

The debt–equity ratio is a financial value indicating the relative proportion of shareholder equity and debt used to finance a company's assets, also known as risk, gearing or leverage. As a firm's asset = debt + equity, if the ratio is greater than 1, the majority of assets are financed through debt. The debt–equity ratio determines the average cost of capital used in the project. A higher equity raises the cost of capital, as equity capital is more expensive. There is, however, a trade-off, since too high a level of debt increases the risks of bankruptcy. Equity invested in the project is seen by lenders as a sign of strong sponsor commitment. The higher the equity, the higher the risks borne by sponsors, but the fewer the risks for lenders, reducing the cost of borrowing. This is an important indicator for lenders and investors. Investing in a company with a higher debt–equity ratio may be riskier, especially in times of rising interest rates, as additional interest has to be paid. In many countries, the debt–equity ratio is stipulated under corporate law. For power projects, it is specified by the electricity regulator in some countries.

The ROE measures the rate of return on the ownership interest (shareholder equity) of the common stock owners. It measures a firm's efficiency at generating profits from every unit of shareholder equity. The ROE shows how well a company uses investment funds to generate earnings growth. ROEs between 15 and 20% are generally considered good. The ROE is defined as the amount of net income returned as a percentage of shareholders equity, expressed in the following formula:

$$\text{ROE} = \frac{\text{Net income}}{\text{Equity}}$$

As a dividend is the actual proceed from the income that is received by the equity investors, in the IAEA's Model for Financial Analysis of Electric Sector Expansion Plans (FINPLAN), ROE is defined as the ratio between dividend and equity capital.

Return on assets is an indicator of how profitable a company is relative to its total assets. Real option analysis (ROA) indicates how efficient management is at using its assets to generate earnings. Calculated by dividing a company's annual earnings by its total assets, ROA is displayed as a percentage:

$$\text{Return on assets} = \frac{\text{Net income}}{\text{Total assets}}$$

Return on assets gives an indication of the 'capital intensity' of the company. It depends on the industry: companies that require large initial investments will generally have lower ROAs. Those ROAs over 5% are generally considered good.

Debt service coverage ratio (DSCR) assesses the financial sustainability of a project. A project might have a high IRR, but might not be eligible to receive financing if the timing for the operating cash flow does not match the needs, in this case the debt service payment to the lenders. Debt servicing includes the total annual payment of all principal and interest.

Debt serviceability is calculated as the ratio between the cash available, in the project account in a year, and the cash needed for payments of interest and principal in the same year. It is calculated for each year of project operations, as it is meaningless during the construction phase, using the formula:

$$DSCR = \frac{OCF_t}{(K_t + I_t)}$$

where OCF_t is the operating cash flow in the year t, and K_t and I_t are the payment on the principal and interest in year t, respectively:

$OCFt$ = total revenue – fuel and operating costs – insurance fees – taxes

A DSCR higher than 1 means that enough cash is available to meet the debt obligation. It is a popular benchmark used in the measurement of a person's or corporation's ability to produce enough cash to cover its debt (including lease) payments. A project with a DSCR of 0.8 only generates enough income to pay for 80% of the yearly debt payments. However, if a project has a DSCR of more than 1, the property generates enough revenue to cover annual debt payments. This is a minimum ratio accepted or stipulated by lenders; it may be a loan condition. Under certain circumstances, breaching a DSCR covenant can be an act of default. The higher the risk of the project, the more risk averse are the lenders, who would insist on a higher DSCR to secure a high safety margin.

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ABBREVIATIONS

AMP	ageing management programme
AMR	ageing management review
BCE	base cost estimate
BCR	benefit–cost ratio
BIS	bid invitation specification
BWR	boiling water reactor
CANDU	Canada Deuterium Uranium (Canadian pressurized heavy water reactor)
CAPEX	capital expenditure
CBA	cost–benefit analysis
CNE	Central Nuclear Embalse (Argentina)
CNEA	National Atomic Energy Commission (Argentina)
CNEN	National Nuclear Energy Commission (Brazil)
CPI	consumer price index
CRDM	control rod drive mechanism
DSCR	debt service coverage ratio
EBITDA	earnings before interest, taxes, depreciation and amortization
EDF	Électricité de France
EIA	environmental impact assessment
FSAR	final safety analysis report
GHG	greenhouse gas
I&C	instrumentation and control
KPI	key performance indicator
LCOE	levelized cost of electricity
LRA	licence renewal application
LTO	long term operation

NPP	nuclear power plant
NPV	net present value
NRC	Nuclear Regulatory Commission
OECD	Organisation for Economic Co-operation and Development
OLE	operating licence extensions
O&M	operation and maintenance
PHWR	pressurized heavy water reactor
PLEX	plant life extension
PLiM	plant life management
PSA	probabilistic safety assessment
PSR	periodic safety review
PWR	pressurized water reactor
RBMK	Reaktor Bolshoy Moshchnosti Kanalniy (High Power Channel–Type Reactor)
R&D	research and development
RFQ	request for quotation
ROA	real option analysis
ROE	return on equity
SSC	structure, system and component
TLAA	time limited ageing analysis
WACC	weighted average cost of capital
WWER	water cooled water moderated power reactor
UNFCCC	United Nations Framework Convention on Climate Change

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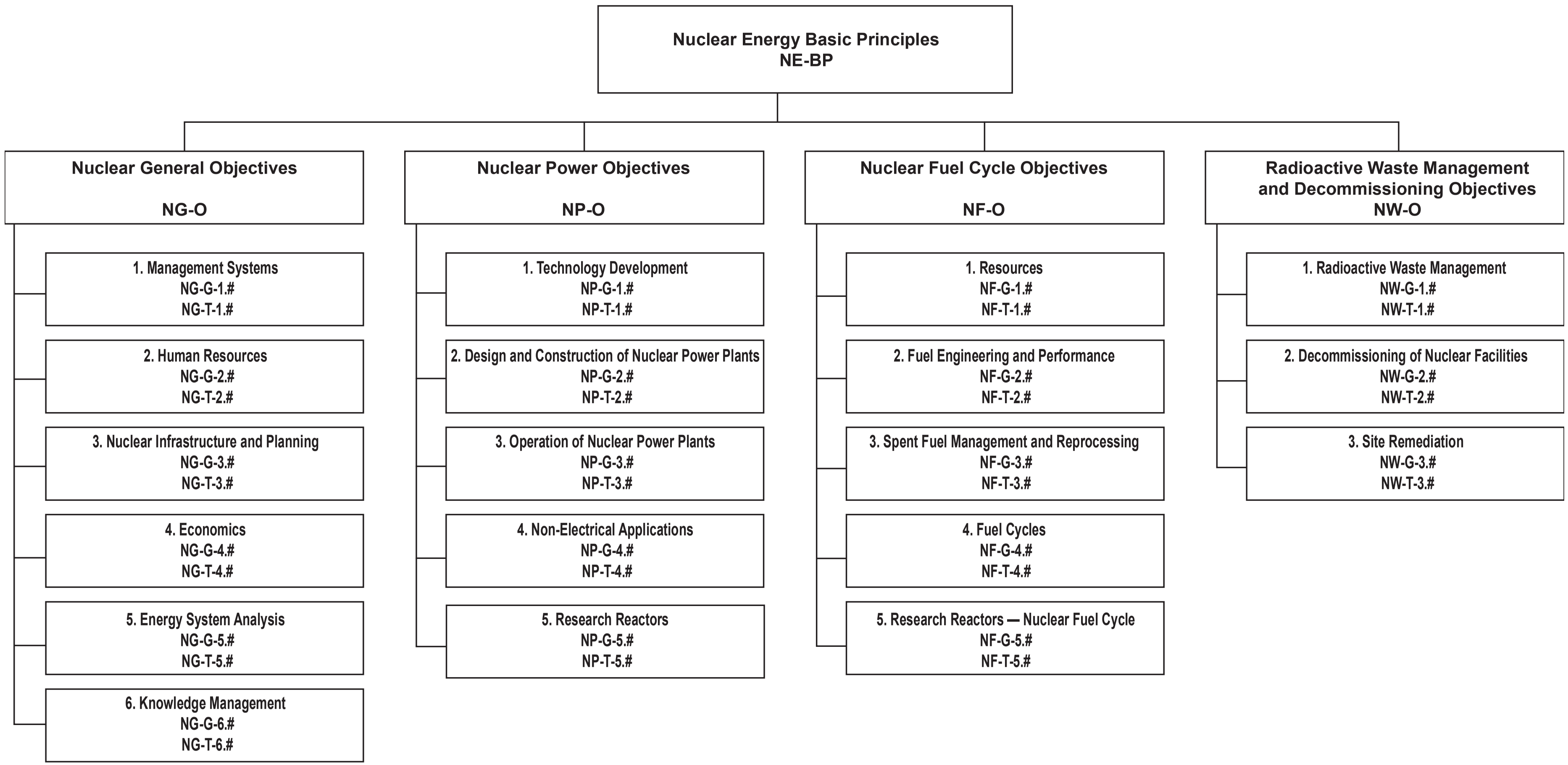

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ISBN 978–92–0–104218–7
ISSN 1995–7807