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APPROACHES FOR ASSESSING THE ECONOMIC COMPETITIVENESS OF SMALL AND MEDIUM SIZED REACTORS

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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 R&D 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.

To be competitive in anticipated markets, small and medium sized reactors (SMRs) rely on design and deployment approaches that are able to offset the adverse impacts of economy of scale. Such approaches include design simplification resulting from the application of safety design features that are the most appropriate for reactors of smaller capacity; the economy of mass production of multiple prefabricated modules; the option of incremental capacity increase, with possible benefits resulting from accelerated learning; sharing of common equipment and facilities; shorter construction periods, unit timing (spread of investments over time); and, possibly, greater involvement of local industry and local labour. The effectiveness of all of these approaches to SMR design and deployment depends on the application and on market variables, such as interest rates, and needs to be assessed and demonstrated for specific cases.

Upon the advice and with the support of IAEA Member States, the IAEA provides a forum for the exchange of information by experts and policy makers from industrialized and developing countries on the technical, economic, environmental and social aspects of SMR development and implementation in the twenty-first century, and makes this information available to all interested Member States by producing status reports and other publications dedicated to advances in SMR design and technology development.

This report was prepared to assist existing and potential stakeholders in Member States in understanding the economic competitiveness of SMR technologies compared to other energy sources and large reactors (LRs); to provide information on available approaches and frameworks to assess the economic competitiveness of advanced SMRs and LRs under specific conditions of their application; and to share knowledge on positive experiences of several Member States that are introducing SMRs into their energy mix.

The report is intended for a variety of stakeholders including: design organizations involved in SMR development programmes; investors and potential users of innovative SMRs; and officers in the ministries or atomic energy commissions in Member States responsible for implementing nuclear technology development programmes or evaluating nuclear power deployment options in the near, medium and longer term.

The main sections of this report highlight the experience with and future plans for SMRs in several Member States, and present the available methodological options to assist design organizations and guide potential users on the economic performance and investment attractiveness of SMRs. The report also provides recommendations on how to apply the available methodologies and define a framework for subsequent comparative assessment studies of different deployment strategies for different nuclear power plants under various possible conditions of their application.

The annexes contributed by Member States provide in-depth descriptions of different assessment methods, give examples of their application, suggest further developments towards a consolidated methodology and also offer more details of the experience of Member States.

The IAEA wishes to acknowledge the assistance provided by the contributors and reviewers listed at the end of the report, especially the contribution made by M.-K. Laina (Greece) and K.R. Qureshi (Pakistan), and the review by D.E. Shropshire (Joint Research Centre, European Commission). The IAEA officers responsible for this project were V.V. Kuznetsov and M.H. Subki of the Division of Nuclear Power.

EDITORIAL NOTE

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CONTENTS

SUMMARY

This report was prepared with the following objectives: (i) to assist existing and potential stakeholders in Member States in understanding the economic competitiveness of small and medium sized reactor (SMR) technologies compared to other energy sources and large reactors (LRs); (ii) to inform available approaches and frameworks to assess the economic competitiveness of advanced SMRs and LRs under specific conditions of their application; and (iii) to share knowledge on positive experiences of several Member States that have introduced SMRs into their energy mix.

To make SMRs attractive and competitive, it is necessary to reduce the risk of investment by verifying the technology itself, and by enhancing and incorporating the accumulated experience associated with the implementation of this technology. To satisfy these criteria, it may be necessary to offer those SMR technologies that are currently implemented widely, and already have a track record of success and a developed industrial infrastructure. Newer SMR technologies may need to be deployed first to niche markets in the nuclear power plant supplier countries in order to establish a technological base and related infrastructure prior to offering them to developing countries.

Argentina, Canada, China, France, India, Italy, Japan, the Republic of Korea, Pakistan, the Russian Federation and the United States of America are countries with active programmes on SMR design development and deployment. Argentina is developing an indigenous innovative integral design pressurized water reactor, known as Central Argentina de Elementos Modulares (CAREM)-25, and completed site excavation to prepare for a 27 MW(e) prototype plant construction at the end of 2013. After the CAREM-25 prototype is constructed, commercialization is expected to start with modular units of different capacity ranging from 150 to 300 MW(e). The Chinese example shows that even in a country with high energy requirements, there is potential for including SMR technology, and it highlights the advantage of SMR technology in the sense of being small and modular, even if LRs suitable for meeting the country's high energy requirements are the basis for the ongoing nuclear power programme. The Indian nuclear power programme provides an example of the role of SMR technology in helping a country to develop its nuclear capacity through gradual expansion from the beginning. India had no choice other than to start with nuclear power reactors of small capacity as the electrical grids could not accommodate LRs because they were small and independent. The Russian Federation has an industrial infrastructure in place to develop a large nuclear energy programme that utilizes reactors of varying sizes. While the country continues to design and build LRs, it is currently developing SMRs for remote applications that can be used within land based or floating nuclear power plants. The United States Department of Energy has recently secured funding to support design certification review by the United States Nuclear Regulatory Commission for up to three advanced SMRs, starting in mid-2014.

Several methods and models are being developed in Member States and international organizations that could assist design organizations and guide potential users on the economic performance of SMRs. Of the IAEA's analytical tools, the models that are most applicable to assess the potential role and competitiveness of SMRs are MESSAGE and FINPLAN. MESSAGE considers the full range of energy supply options, together with all relevant infrastructure facilities and resources, including the capability to incorporate technical, economic, environmental, regulatory and policy constraints. It identifies an optimal portfolio of energy supply facilities that should be built/expanded over time to meet the expected future energy demand, by minimizing the total energy supply cost. FINPLAN assists in evaluating the financial viability of the investment plan determined by MESSAGE analysis. It is designed to evaluate the financial implications of an expansion plan for a power generating system of all technology types. Both models can be used interactively to conduct an integrated analysis. The output of the FINPLAN can be used to modify the inputs to MESSAGE, if the given financial resources do not support the MESSAGE proposed investment plan. MESSAGE and FINPLAN assess SMRs as one of the energy options.

There are models for addressing aspects of SMR competitiveness and assessing the investment risks of SMR based projects. Firstly, the levelized unit electricity (or energy) cost (LUEC) model yields the electricity cost in $/MW·h. The LUEC model is a simplified measure; it assumes constant expenditure and production profiles over the lifetime of a plant. It provides a benchmark for comparing competing reactor technologies with each other and with regards to alternative energy sources. The Generation IV spreadsheet calculation of nuclear systems (G4-ECONS) is a Microsoft Excel based tool that calculates the LUEC for multiple types of nuclear energy system. Each section of the model computes a component of the total LUEC, which can be divided into four life cycle

components: recovery of capital, non-fuel operation and maintenance, fuel cycle costs, and annual funding of decontamination and decommissioning.

The present value capital cost (PVCC) is a generic model assessing various factors affecting the effective capital cost when several nuclear power plants are built in a sequence. Its application is not limited to comparative assessments of SMRs versus LRs, and it could be useful in all cases when a sequential deployment of several nuclear power plants is considered. The factors included in the model are economy of scale, multiple units, learning, construction schedule, unit timing and plant design. The factors assessed by the PVCC model would be important if a deployment of several SMRs versus fewer LRs were considered. The PVCC model could be used as an input (elasticity) to the LUEC model.

In addition, the model for systematic assessment of reduced design complexity is based on a simple screening method, and can be used by design organizations of advanced SMRs for comparing alternative design approaches to plant simplification from an economic perspective on the basis of a common competitive target, starting from the early design stages. The model discriminates between external parameters that remain beyond the control of a design organization, and design and project parameters for which different values could be included in screening to determine the conditions under which various design alternatives become competitive.

To cope with uncertainties, such as the costs of materials for power plants and the prices of organic fuel, calculations of the figures of merit, such as LUEC, could be performed using the Monte Carlo method. The uncertainties could be taken into account by defining the uncertainty ranges, assigning probability distribution functions to each of the input variables and, then, by using a Monte Carlo random number generator to generate random values of each of the input variables, for the subsequent multiple calculations of a selected figure of merit. The goal of adding the uncertainties is to provide more informative results compared to those obtained with best estimate calculations alone.

Scenario analysis models are typically intended to perform simulations of large expanding energy systems over a long period of time. The main kernel of these models is dynamic simulation of material flows. Once a dynamic material flow analysis (MFA) is accomplished, this provides a basis for many ancillary analyses, possibly including simulation of the economics and investments. As the goals of a typical MFA are multiple, the economic/financing models used are often simplified, if present at all. Incorporation of more detailed economic models is, however, not precluded. The dynamic nature of the MFA outputs and coverage of a complete energy system are important. Separate models for the assessment of the investment attractiveness of SMR based projects could be applied in a consolidated way.

The integrated model for competitiveness assessment of SMRs (INCAS), developed by the Politecnico di Milano, Italy, provides a framework for a consolidated approach to the combined application of assessment models. INCAS focuses on the comparative assessment of deployment scenarios with SMRs and LRs. It consists of an investment model and an external factors model. The investment model is developed with a modular approach, with separate models to calculate cash flow profiles and economic and financial indices. The external factors model attempts to consider some social and market related factors that could be subjective and non-quantifiable, but are likely to produce a certain impact on decision making regarding different nuclear options. At the end, the analytical hierarchy process merges together the results of the financial assessment and the stakeholders' judgements on the external factors to make a final judgement on the attractiveness of an SMR based nuclear project.

This report intends to provide an overview of the available approaches for assessing the economic competitiveness of SMRs versus alternative energy options and LRs. None of the methodologies have been validated by the IAEA, except for the models and packages developed by the IAEA. It is left to the judgement of Member States to decide on which methodology is most suitable for their requirements.

1. INTRODUCTION

1.1. GENERAL INTRODUCTION

There is a growing interest in the development and deployment of small and medium sized reactors (SMRs), which can be seen through the numerous concepts that are under design certification, the various units that are under construction, the expanding of potential markets in developing countries, and the increasing efforts of the IAEA to foster international collaboration for improving the development and deployment, and the economics of SMRs. Owing to the projected large increase in global energy demand resulting from high population growth and rapid economic development in developing countries, the expectations for the role of nuclear power in the future are rising. SMR design organizations are pursuing new approaches, trying to take advantage of certain benefits of the innovative technology associated with design simplification and improved operability. More than forty five innovative concepts and designs of SMRs for electricity generation and process heat production, desalination, hydrogen generation and other applications are under development in more than fifteen countries.

Even though SMR designs and concepts are numerous and ambitious, their deployment is not an easy task, as there are many challenges; one such challenge is their economic competitiveness. SMRs do not benefit from economies of scale. Instead, substantial efforts of their design organizations are targeted at the improvement of plant economy. Nevertheless, according to studies organized by the IAEA, scaling losses can be countered by factors such as lower investment risk, improved cash flows and shorter construction periods. The competitiveness of SMRs depends both on overcoming the lack of economies of scale and on finding a suitable niche for them. Therefore, developing methods for assessing the economic competitiveness of SMRs is of paramount importance, as is identifying the characteristics of potential markets [1]. The IAEA facilitates its Member States in identifying various designs and deployment strategies by providing information about several approaches for assessing SMR competitiveness. The present report collects, assesses and presents best practices in Member States with regard to the economic competitiveness of SMRs, and analyses models that can be used for evaluating the economic performance of SMRs versus other energy options and for comparing a number of SMRs to large reactors (LRs) with an overall equal capacity.

1.2. BACKGROUND

1.2.1. Rationale and developments in Member States

There is ongoing interest in Member States in the development and deployment plan of SMRs. According to the classification that is adopted by the IAEA, small reactors are reactors with an equivalent electric power less than 300 MW, while medium sized reactors are reactors with an equivalent electric power between 300 and 700 MW.

SMRs may provide an attractive and affordable nuclear power option for developing countries with small electrical grids and limited investment capability. Multimodule power plants with SMRs may offer energy production flexibility that energy market deregulation might call for in the future in many countries. SMRs are also applicable for cogeneration and advanced process heat applications.

Several Member States have SMR designs ready for deployment. These include pressurized heavy water reactors (PHWRs), such as PHWR-220, PHWR-540 and PHWR-700 by the Nuclear Power Corporation of India Limited (NPCIL). China has developed and deployed 300 and 700 MW(e) class pressurized water reactor (PWR) designs. In the Russian Federation, construction of a pilot floating cogeneration plant with two water cooled KLT-40S reactors started in June 2006 and has now neared 95% completion, preparing for commissioning in 2016. Its deployment date will be 2016. In the first half of 2012, 14 SMRs were under construction in 6 countries [2]. The recent construction of pressurized heavy water SMRs in India and Romania has been on schedule.

In addition, advanced SMR designs are under development for all principal reactor lines and some non-conventional combinations. As of 2012, numerous advanced SMR concepts and designs were at different stages of development within national or international programmes, involving both developed and developing countries. The target dates when they could be ready for deployment range from 2016 to 2030 [3, 4].

The SMRs that are ready for immediate deployment or that will be developed for deployment within the next decade are, in most cases, intended for markets different from those in which large nuclear power plants operate, i.e. markets that value more distributed electrical supplies, a better match between supply increments and the investment capability or demand growth, more flexible siting or greater product variety. These markets have different investment, siting, grid, infrastructure, application and other conditions and limitations.

Therefore, the factors affecting the competitiveness of SMRs in such markets are expected to be different from those observed in established markets for electricity production. For example, upfront investment capability may be limited, which would favour capacity addition in smaller increments; grids may be small or constrained, which may favour smaller capacities suitable for such grids; infrastructure and human resources may be insufficient, which would favour less complex operation and maintenance (O&M) requirements; and non-electric energy products, such as potable water, which would favour plant locations reasonably close to the customers.

Another point is that an SMR does not necessarily mean small or medium sized nuclear power station. As with any nuclear power plant, several multimodule SMRs can be built at a site, or as twin units. A series of SMRs can be considered comparable to fewer larger plants to achieve the same overall power station capacity. In this case, SMRs have the potential to be competitive by employing alternative design approaches, taking advantage of smaller reactor size, offering a less complex design and O&M, but by relying on a deployment in series approach and taking advantage of accelerated learning, sharing of the on-site facilities, unit timing (spread of the investment in time) and shorter construction duration.

For longer term SMR designs, flexible plant capacities with several or multiple reactor modules are foreseen, and the modules are assumed to be factory fabricated, fuelled and, in some cases, designed for operation without on-site refuelling [3, 4]. In this case, accelerated learning in construction and the economy of mass production in a factory can be taken into account.

Some simpler SMR designs have the potential to involve national industry, contributing to increased national infrastructure development and deployment. As they are difficult to quantify, such social and macroeconomic factors may also affect decision making regarding a nuclear power project and need to be taken into account when assessing the competitiveness of a nuclear power project.

Finally, national as well as global economies are prone to periodic crises and perturbations of boundary conditions, such as changes in electricity prices and commodity prices. SMRs, under certain conditions, may be competitive with LRs. To be competitive, it would be necessary to overcome the lack of economies of scale and to find a suitable niche for SMRs. However, to obtain a quantitative evaluation of risk tolerance of a nuclear power plant project, methods of sensitivity and uncertainty analysis need to be applied in economic analyses.

All of the above mentioned considerations indicate that an adequate assessment of SMR competitiveness cannot be based solely on a generation cost analysis involving only economy of scale considerations. When a number or a series of power plants is being considered, the assessment becomes a complex task in which many factors complementary to the economy of scale need to be taken into account. The assumption of constant expenditure and production profiles may not work well in such an assessment, and an option to deal with time dependent characteristics would need to be introduced. An uncertainty analysis becomes important, as boundary conditions are likely to change as deployments progress. Finally, an assessment may benefit from taking into account additional factors and long term risks related to social, macroeconomic and energy security considerations.

While methodologies and software tools for taking into account certain groups of the above mentioned factors are being elaborated in and applied by Member States and international organizations, the overall consolidated approach to the application of such methodologies for comparative assessment of the investment attractiveness of SMR based projects has not yet been established.

Reflecting developments in Member States, the IAEA has prepared this report to highlight all of the major economics and investment related factors that may affect SMR competitiveness, as well as models and tools available to assess these factors and combinations thereof. The IAEA is also conducting a series of case studies performed in Member States to examine the competitiveness of smaller reactors in a variety of possible deployment approaches, and fosters the development of a consolidated methodology for the assessment of economic and investment attractiveness of SMR based projects.

1.2.2. Previous IAEA publications

IAEA-TECDOC-1485, Status of Innovative Small and Medium Sized Reactor Designs 2005, Reactors with Conventional Refuelling Schemes [4] and IAEA-TECDOC-1536, Status of Small Reactor Designs Without On-site Refuelling [5], issued in 2006 and 2007, respectively, present the status of design and technology for innovative SMRs developed worldwide. Concise design descriptions are also provided in the Status of Small and Medium Sized Reactor Designs: A Supplement to the IAEA Advanced Reactors Information System (ARIS)[1] that was published in September 2011. The design descriptions of SMRs presented in these reports identify their anticipated applications, provide evaluations of some economic characteristics and explain the design and deployment approaches pursued by design organizations to achieve SMR competitiveness in targeted markets. The design descriptions provided in these reports, although producing some insights on how competitiveness of SMRs could be achieved, neither suggest nor follow a common method in the evaluation of economic and investment characteristics of nuclear power plants with such reactors. As they are limited in volume, the design descriptions do not provide sufficient details of such evaluations.

IAEA-TECDOC-1575 Rev. 1, Guidance for the Application of an Assessment Methodology for Innovative Nuclear Energy Systems, INPRO Manual — Overview of the Methodology, Vols 1 and 2 of the Final Report of Phase 1 of the International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO) including a CD-ROM comprising all volumes [6] contains a chapter on economics, which defines user requirements to innovative energy systems and suggests a method for innovative nuclear system economic assessment based on comparison with alternative energy sources. IAEA-TECDOC-1434, Methodology for the Assessment of Innovative Nuclear Reactors and Fuel Cycles [7] also briefly describes the IAEA tools used for comparative assessment of nuclear and non-nuclear energy options (such as WASP, MAED and MESSAGE), the scenario code DESAE developed by INPRO, and an economic optimization code SYRTEX developed in the Russian Federation, with references being provided in all cases. The methodology for economic evaluation of innovative nuclear energy systems is presented in a generic way, making specific consideration neither of SMRs nor of a totality of the factors that may become important when nuclear power plants with smaller reactors are compared to those with reactors of larger capacity in terms of economics and investments.[2]

The present report provides a broad and detailed summary of state of the art analytical methods, models and tools developed and applied in Member States, with a special focus on new developments, attempting to take into account all factors important for competitiveness assessment of SMRs. It also suggests a consolidated approach to the application of such methods for comparative assessment of the investment attractiveness of SMR based projects against those with reactors of larger capacity. To avoid duplications, the methodologies and tools presented in Ref. [6] and elsewhere are just referenced or summarized briefly, when necessary.

1.3. OBJECTIVES

The report is intended for a variety of stakeholders, including design organizations involved in SMR development programmes, investors and potential users of innovative SMRs, as well as for officers in the ministries or atomic energy commissions in Member States responsible for implementing nuclear technology development programmes or evaluating nuclear power deployment options in the near, medium and longer term. The overall objective of this report is to assist existing and potential interested stakeholders in the definition of competitive approaches regarding design and deployment of SMRs. The specific objective of this report is to define a framework for subsequent comparative assessment of design and deployment approaches for advanced SMRs and LRs under various possible conditions of their application.

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[1] The booklet can be downloaded from: http://www.iaea.org/NuclearPower/Downloads/Technology/files/SMR-booklet.pdf

[2] As they are elaborated and consolidated, the methods described in the present report could eventually be included in further revisions of the INPRO methodology.

1.4. STRUCTURE AND SCOPE

Section 2 summarizes the development status of advanced SMRs, points to a dilemma of technology innovation versus design provenness, and reflects on how it may affect potential deployment of advanced SMRs, also highlighting a potential pathway to resolution.

Section 3 summarizes experience with, and future prospects for, SMRs in Argentina, China, India, Pakistan and the Russian Federation. More details about experience and prospects are available in Annexes I, IV, V and VI, which were contributed by Member States.

Section 4 provides a review of the methods and models, developed in Member States and international organizations, that could assist design organizations and guide potential users on the economic performance of SMRs. An introduction is provided in Section 4.1, which identifies the scope of all other sections. Section 4.2 gives an overview of the currently available IAEA models and tools for energy planning. More details are provided about the MESSAGE and FINPLAN codes, explaining their capabilities relevant to SMR competitiveness assessment and giving a summary of their application experience for planning of nuclear energy options with smaller reactors. Section 4.3 provides a summary of simple models that could be used to assess competitive design and deployment of SMRs versus larger reactors and acts as a ‘navigation tool’ for Sections 4.4 and 4.5. Section 4.4 presents separate assessment methods and models available for the purpose identified in Section 4.3. Finally, Section 4.5 highlights the activities, ongoing in Italy, targeted at the consolidation of models for comparative assessment of the investment attractiveness of SMR based versus LR based projects, and presents a possible framework for such a consolidated approach. Sections 4.4 and 4.5 were developed based on the contributions from Member States presented in Annexes II, III, V, VIII and IX of this report.

Section 5 provides conclusions.

The scope of the report covers the ongoing efforts on the development of models for assessing the economic competitiveness of SMRs with other energy options and with large nuclear plants and a consolidated framework that includes various models for assessing the economic performance of a series of SMRs versus LRs of equal capacity based on inputs provided by Member States and relevant stakeholders.

1.5. APPROACH TO THE PREPARATION OF THIS REPORT

The summary and cross-cutting sections were developed by international experts and the Secretariat, and reviewed by most of the contributors to this report. The structure of the report and the conclusions were elaborated through the effort of two IAEA technical meetings in October 2007 and July 2008, and a consultants meeting in March 2006.

All annexes of this report were prepared by national experts in Member States nominated for this activity by their respective governments.

2. ADVANCES IN SMR TECHNOLOGY AND CONSIDERATIONS OF DESIGN PROVENNESS

2.1. DEVELOPMENT STATUS OF ADVANCED SMRs

In 2012, several proven and in operation SMR designs were available for immediate deployment, including PHWR-220 or PHWR-540 from NPCIL (India), and small and medium sized PWRs of Chinese design [5]. The fact that these and other SMRs continue to be deployed indicates that they are competitive for the conditions of their deployment and application [8]. Worldwide, 131 SMR units are in operation in 25 Member States, with a capacity of 63 GW(e). At present, 14 SMRs are under construction in 6 countries. Especially with PHWRs, many recent deployments were accomplished in line with the schedule and within the originally defined budget. Approximately 45 innovative SMR concepts are under research for electricity generation and for process heat production, for desalination, hydrogen generation and other applications. SMRs are under development for all principal reactor lines, i.e. light water reactors (LWRs), heavy water reactors (HWRs), gas cooled reactors (GCRs) and liquid metal cooled reactors.

For about a dozen of the advanced SMR concepts, current progress in developing the technology and finalizing the design suggests possible deployment within the next decade [8].

In the Russian Federation, construction of a pilot floating cogeneration plant of 300 MW(th)/70 MW(e) with two water cooled KLT-40S reactors began in June 2006. Its deployment date is by 2016. Plans were announced to build five such plants and also two plants with 11 MW(e) ABV reactors for customers in the Russian Federation.

Several integral PWR designs are well advanced in their development, and some could be available for deployment around 2015–2020. Argentina has completed site excavation for constructing a 27 MW(e) prototype of the 150–300 MW(e) CAREM design. The 330 MW(th) system integrated modular advanced reactor design, developed in the Republic of Korea for a cogeneration plant, received standard design approval in July 2012.

In India, construction is expected to start on the first 300 MW(e) advanced HWR, which has been developed for cogeneration applications. The reactor is designed to operate with ^{233}U–Pu–Th fuel; it uses boiling light water as a coolant and heavy water as a moderator.

China is developing a modular high temperature GCR pebble-bed module (HTR–PM), with each module having a capacity of 250 MW(th) or 100 MW(e). It is a high temperature GCR with pebble bed fuel and an indirect supercritical steam energy conversion cycle. A two module plant configuration of HTR–PM is under construction and is foreseen for the commercial version of this reactor, yielding an electric output of 200 MW(e). China has also been developing the ACP-100, a small advanced passive PWR.

In Japan, Toshiba Corporation, in cooperation with the Central Research Institute of Electric Power Industry and Westinghouse Electric Company, is developing a 4S sodium cooled reactor. It has a design power of 10 MW(e) and a refuelling interval of 30 years.

In the United States of America (USA), four integral pressurized water SMRs are under development, including Babcock and Wilcox’s mPower, NuScale Power, Holtec’s SMR-160 and the Westinghouse SMR. The mPower plant design consists of twin 180 MW(e) modules, and its design certification application is expected to be submitted in mid-2014. NuScale Power envisages one nuclear power plant made up of 12 modules (45 MW(e)) and plans to apply for design certification with the US NRC in 2015. The Westinghouse SMR is a conceptual design with an electrical output of 225 MW(e), incorporating passive safety systems and proven components of the AP1000.

The fact that many of the above mentioned and other advanced SMR designs incorporate certain degrees of technology innovation and have not been proven in operation so far brings forward the issue of how these designs could comply with the basic requirement of design provenness imposed by many potential users, specifically, those from developing countries [9].

2.2. CONSIDERATION OF DESIGN PROVENNESS

In the forthcoming decades, nuclear power may become an increasingly attractive option due to environmental problems, such as pollution and greenhouse emissions, and the security of supply issues that are associated with fossil fuels. While the increasing profitability of nuclear power may attract utilities to this technology, large capital costs combined with a politically volatile environment act to hamper investor confidence. When utilities are asked to invest in new technologies that lack proven experience, investor risk is further enhanced. To eliminate or compensate for the increased uncertainty associated with novel technology, additional conditions need to be satisfied with regard to verification of the technology itself and the factors surrounding its effective implementation. To address this problem, the current section will examine several considerations, complying with which may reduce the investment risk of SMR technologies, thereby enhancing investor confidence. Section 2.2.1 will examine the verification of novel technology, Section 2.2.2 will discuss factors associated with the design implementation and Section 2.2.3 will provide a brief description of the interaction between SMR technology and the economic realities of the developing world.

2.2.1. Verification of novel technology

Of the various factors that are pertinent to investor confidence, the first concerns the central issue of the technology itself. To have confidence in a novel technology, it is necessary to verify that the technology in question is safe, reliable and economic, thus satisfying regulatory and commercial constraints. In this regard, the means of the verification process and the extent of the testing involved will vary depending on whether the advanced technology represents an evolutionary design or an innovative design.

As defined in Ref. [10], an 'evolutionary' design involves small quantitative changes in comparison with its parent technology, not large quantitative jumps nor qualitative changes of the concept. For evolutionary designs, the verification process requires engineering and confirmatory testing of the new design features without requiring a demonstration plant.

At the other extreme, 'innovative' design [11] involves qualitative changes in the concept itself and, thus, represents a new technology. Examples of such qualitative changes would be the conceptual changes due to a switch from water cooled to gas cooled or liquid metal cooled reactors. The changes required are so radical that substantial research and development (R&D), feasibility tests and a prototype or a demonstration plant would probably be required to verify the new technology. In the 1950s, small demonstration plants were built for water cooled reactors because, at that time, that technology had yet to be established. This same process of building larger demonstration plants was also observed for sodium cooled reactors during the 1960s through to the 1980s, and beyond.

Between the limits of evolutionary and innovative designs, some designs may involve sizeable changes in comparison to the parent technology, which are more than quantitative but do not involve a qualitative conceptual change in the technology itself. Depending on the magnitude of these changes, the new design may range from being slightly more complicated than an evolutionary design to being nearly as complicated as an innovative design. For such designs, the degree of testing required for verification is intermediate between that required for evolutionary and innovative designs, and increases according to the design changes. As an example of the required verification for these types of changes, the design certification of AP600 and AP1000 in the USA by the NRC required an extensive experimental testing programme of their novel features, but did not require a demonstration plant to verify the technology [12]. This was because the AP600 and AP1000 designs, although they include certain novel features, remain within the qualitative paradigm of LWR technology.

2.2.2. Implementation of verified technology

While verification of a novel technology is necessary for enhancing investor confidence, it is not in itself sufficient, due to several factors associated with the implementation of this technology. Among factors that can increase the economic risk are the following[3]:

- Delays in licensing in developing countries, due to a possible lack of qualified personnel (these delays could be minimized if the design has been licensed in the nuclear power plant supplier country and has a track record of good operational experience);
- Construction cost overruns not linked with licensing, such as improper site qualification and inexperienced local contractors;
- Failure or substandard performance of the equipment;
- Delays in operational staff training and qualification;
- Long procurement periods for components and qualified spare parts due to the absence of experience and substandard performance of equipment;
- A restricted number of spare part suppliers in the market or even the non-existence of such suppliers if the plant is of a unique type;
- The non-availability of full scope plant simulators, which could delay the training of operating personnel;

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[3] These factors may apply to advanced reactors of any capacity, not only SMRs.

— Potential nuclear accidents;
— Uncertainties with regard to disposal of spent fuel and high level radioactive waste.

It should be noted that smaller reactors may have certain advantages over large ones when it comes to risk tolerance for some of the above mentioned factors[4]. In addition, SMRs have generally smaller staffing requirements than LRs. As an example, there are several recent cases of SMRs (PHWR) being deployed in countries other than the country of origin in line with the planned schedule and within budget [8], while construction delays and cost overruns in foreign deployments of larger reactors have become fairly frequent. However, to make adequate conclusions, all risk factors important for comparing different nuclear power options need to be analysed in a consistent manner, based on a common methodology.

The IAEA is coordinating a series of case studies performed in Member States to examine the competitiveness of smaller reactors in a variety of possible deployment approaches, and fosters consolidation of the methods and models for assessment of the investment attractiveness and investment risks of SMR based projects.

2.2.3. SMRs in the developing world

While the above mentioned considerations are present in all markets, they tend to be especially pronounced in some developing countries. Whereas the developed world currently deploys mostly LRs matching its large electricity consumption, the smaller electrical grids, the limited investment capabilities and the lack of operational background for LRs in some developing countries may drive the utilities towards the adoption of SMRs. Accordingly, to make SMRs attractive, it is necessary to reduce the investment risk by thoroughly verifying the technology itself and by enhancing the accumulated experience associated with the implementation of this technology. To satisfy both of these criteria, it may be initially necessary to offer only those SMR technologies that are currently widely deployed and, therefore, already have a strong track record of success and a well developed industrial infrastructure. In contrast, newer SMR technologies may need to be deployed first to niche markets in the nuclear power plant supplier countries in order to establish the experience base and the related infrastructure prior to offering them to developing countries.

In some nuclear power plant supplier countries, a barrier for advanced technologies is licensing duration. For example, in the USA, to achieve design certification, the NRC may require up to six years for an SMR based on LWR technology. When potential private investors see this delay, they invest in other technologies, such as smart grid and niche renewables.

Examples exist, albeit in the developed world, when a first of a kind plant based on water cooled reactor technology is deployed in a country different from the country of origin, e.g. the European Power Reactor Finland plant in Olkiluoto, or the AP1000 units in China [8]. During the past two to three decades, several developing countries have developed a capability to design and manufacture SMRs indigenously, relying on local materials and local labour (examples are Argentina, China and India). Some of these designs offer attractive capital cost characteristics, reflective of the localization[5] content. In addition, importantly, technology transfer could play an important role in achieving competitive deployment of nuclear power plants worldwide.

Addressing established SMR technologies, the next section provides an overview of examples of experience with SMRs and lessons learned in the previous two decades.

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[4] There are well researched reasons for the massive cost and time overruns of large, not necessarily nuclear projects as compared to smaller ones, for example, see Ref. [13].

[5] The term ‘localization’ refers to the participation of local industry in the construction of nuclear power plants. Localization can be deep or shallow. Deep localization would involve establishment of conversion, enrichment and fuel manufacturing capabilities, and manufacture of key reactor components. Shallower localization would involve manufacture of pumps, valves and ‘non-nuclear’ components, and involvement in civil engineering aspects.

3. EXPERIENCE WITH SMRs, LESSONS LEARNED IN THE PREVIOUS TWO DECADES AND FUTURE PLANS

As already mentioned, SMR technology could be less risky for investors in developing countries when the SMR is a proven design with an established track record of operating experience and a developed industrial infrastructure capable of supporting the technology. For this reason, the current section examines the respective experiences of Argentina, China, India, Pakistan and the Russian Federation with regard to SMR technology. In each case, the goal is not only to highlight a specific technology, but also to extract general lessons from the respective stories. More details about national experience and future plans with respect to SMRs can be found in Annexes I, IV, V and VII contributed by Member States.

3.1. ARGENTINA'S EXPERIENCE

Argentina is a country with a large territory and sparsely populated (~40 million), which makes building large capacity electrical grids inexpedient. In its nuclear power programme, Argentina first imported nuclear power plants and developed its own technical capacity in parallel. Argentina currently has two operating power reactors that account for 5% of its electricity production. Both of these reactors are SMRs. Atucha 1 is a 335 MW(e), pressure vessel type, HWR that was supplied by Siemens and began operation in 1974. Embalse, in contrast, is a 600 MW(e), pressure tube type, PHWR that was supplied by AECL and which began operation in 1984. With regard to this class of SMRs, current plans are to extend the lifetime of the Embalse plant, and to complete the construction and put into operation Atucha 2 — a pressurized heavy water vessel type reactor for which construction by Siemens began in the 1980s and was then halted.

At present, there are two SMR units in operation in Argentina, while there is one SMR unit under construction, as can be seen in Table 1.

TABLE 1. SMRs OPERATING AND UNDER CONSTRUCTION IN ARGENTINA [2]

Nuclear power plant	Net MW(e)	Reactor type	Reactor model	Commercial start of operation
Atucha (unit 1)	335	PHWR	Two loop	1974
Atucha (unit 2)	692	PHWR	Two loop	2014
Embalse (unit 1)	600	PHWR	CANDU 6	1984
CAREM-25	27	iPWR	Integral loop	2017

Note: PHWR: pressurized heavy water reactor; SMR: small and medium sized reactor.

Production of D_2O has been resumed in Argentina, which has considered building a fourth reactor, and to continue with uranium mining, enrichment and fuel fabrication. Enrichment is clearly important to enhance fuel utilization in the operating reactors. In this respect, Argentina was able to extend the fuel burnup from 6000 to 10 000 MW·d/t U by substituting slightly enriched uranium for natural uranium in the Atucha 1 plant. An option to import reactors of other types is also being discussed.

Finally, apart from expanding its PHWR programme based on imported reactors and the national supporting infrastructure, Argentina is also developing an indigenous innovative SMR known as CAREM-25, and completed site excavation in August 2012 for building a 27 MW(e) prototype (CAREM-25) to demonstrate the CAREM technology.

The purpose of the CAREM project is to develop and construct an innovative, simple and small nuclear power plant incorporating an indirect cycle integral type PWR with some distinct and characteristic features that essentially simplify the design and also contribute to a high safety level.

The distinct design features of the CAREM are:

- Integral primary cooling system with in-vessel steam generators, control rod drives and pressurizers;
- Self-pressurization;
- Passive safety systems.

After the CAREM prototype is constructed, commercialization is expected to start soon, with modular units of different capacity ranging from 150 to 300 MW(e). Natural circulation of the primary coolant is planned to be used in smaller capacity modules of 150 MW(e) and below. The CAREM reactors are expected to cater to the domestic Argentinian requirements and to have an export potential, due to the relatively low capital and O&M costs stemming from the plant simplification as well as the higher hard currency purchasing power in the country.

In summary, the experience of Argentina with SMRs could be a useful background for countries with relatively large territories but small and scattered populations, where there is no incentive to construct large capacity electrical grids, but there is an incentive to achieve benefits in the development of a national industrial capability.

3.2. CHINA’S EXPERIENCE

China is a country with high energy requirements. At the same time, the country has isolated areas or limited electricity grids that can be supplied by SMRs. Currently, 18 nuclear power reactors are in operation in China, and it is expected that this number will begin to rise significantly in the future, since 29 more plants are under construction in the country. The additional current capacity targets are 90 GW(e) by 2020 and 250 GW(e) by 2030. China expects to build reactors based on technology transfer, accelerating its programme following the initial slow buildup of experience in which nuclear power in China was based on foreign technology from Canada, France and the Russian Federation. In addition to its own PWR design, the technologies that are being pursued are high temperature GCRs and fast reactors.

At present, there are eight SMR units in operation in China, while there are three SMR units under construction (Table 2).

With regards to SMR technology, the Qinshan nuclear power plant is a multiunit nuclear power plant with six SMR units in commercial operation and one medium sized reactor under construction. Initially, a small PWR of 288 MW(e) capacity was built, which was the first domestically designed and constructed nuclear power plant in the nation. Following this, the next set of reactors were medium sized PWR plants with a capacity more than 600 MW(e) that were of Chinese design. Finally, two PHWR CANDU 6 reactors were supplied by AECL.

The Changjiang nuclear power plant is under construction and consists of two medium sized PWR units of 610 MW(e) capacity, suitable for the demand of the local electricity grid, which are expected to start operating in 2014 and 2015.

In Shidaowan, a small GCR of 200 MW(e) capacity, the HTR–PM, is under construction, with commercial operation expected to begin in 2016. The main goal of the HTR–PM is to fulfil the requirements of safety, standardization, economy and proven technology. As far as economics is concerned, the objective is that the power plant must be competitive with other types of energy source, including the current PWR, while providing more of a safety margin and a wider range of potential applications.

The Chinese example shows that even in a country with high energy requirements, there is the potential to include SMR technology, and it highlights the advantage of SMR technology in the sense of being small and modular. Although large power reactors suitable for meeting the high energy requirements of rapid economic development are the basis for the ongoing nuclear programme, units in the SMR range of GCR and PWR technology are expected.

The China Experimental Fast Reactor, a sodium cooled 20 MW(e) experimental fast reactor with PuO_2–UO_2 fuel, is currently in operation and was connected to the grid in 2011.

TABLE 2. SMRs OPERATING AND UNDER CONSTRUCTION IN CHINA [2]

Nuclear power plant	Net MW(e)	Reactor type	Reactor model	Commercial start of operation
Shidaowan (unit 1)	200	GCR	HTR–PM	2016
Changjiang (unit 1)	610	PWR	CNP-600	2014
Changjiang (unit 2)	610	PWR	CNP-600	2015
Qinshan (unit I-1)	288	PWR	CNP-300	1994
Qinshan (unit II-1)	610	PWR	CNP-600	2002
Qinshan (unit II-2)	610	PWR	CNP-600	2004
Qinshan (unit II-3)	610	PWR	CNP-600	2010
Qinshan (unit II-4)	610	PWR	CNP-600	2011
Qinshan (unit III-1)	650	PHWR	CANDU 6	2002
Qinshan (unit III-2)	650	PHWR	CANDU 6	2003
China Experimental Fast Reactor	20	FR	BN-20	2011

Note: FR: fast reactor; GCR: gas cooled reactor; HTR–PM: high temperature reactor–pebble-bed module; PHWR: pressurized heavy water reactor; PWR: pressurized water reactor; SMR: small and medium sized reactor.

3.3. INDIA’S EXPERIENCE

The Indian nuclear power programme provides a case study of the role of SMR technology in helping a country to develop its nuclear capacity through gradual expansion from the beginning. In the 1950s, India began planning an indigenous nuclear power programme. As the country had limited amounts of uranium and about one quarter of the world’s thorium, Indian scientists envisioned a three stage programme that would eventually lead to a sustainable nuclear energy system relying only on the indigenous fuel supply. In stage 1 of this programme, PHWRs using natural uranium fuel would be deployed. In stage 2, plutonium and depleted uranium from the used fuel of PHWRs from the first stage would be used in fast breeder reactors (FBRs). With significant FBR capacity in operation, thorium would be introduced in later FBRs to produce ^{233}U. Finally, in stage 3, reactors using ^{233}U–Th fuel would be deployed to ensure sustainability of the nuclear energy system in terms of indigenous fuel supply.

To begin this process, SMR technology was crucial because the country’s electrical grids could not accommodate LRs, as they were small and independent (regional grids). Thus, the capacity of the grids dictated the use of smaller reactors.

At present, there are 20 SMR units in operation in India, while there are 5 SMR units under construction (Table 3).

Owing to the limited grid size, India initially chose the reactors with an electrical capacity of about 200 MW(e), which were built in pairs. In 1964, India bought a pair of 210 MW(e) boiling water reactors from General Electric (USA), and they were put into operation in 1969. Although these LWRs were not consistent with the envisioned three stage plan, they were procured to acquire certain experience of operation and to test the compatibility of nuclear power plants with the Indian electrical grids.

After these LWRs were constructed and put into operation, India began its three stage programme in earnest by constructing a pair of 200 MW(e) PHWRs. The first of these reactors (RAPS-1) was constructed with the assistance of AECL and began operation in 1973. However, when technical cooperation with AECL was discontinued after 1974, India had to fabricate all the necessary components for the second reactor (RAPS-2) indigenously. While this decision delayed the completion and operation of the second reactor until 1981, it helped India to develop the requisite industrial capacity to construct reactors on its own.

TABLE 3. SMRs OPERATING AND UNDER CONSTRUCTION IN INDIA [2]

Nuclear power plant	Net MW(e)	Reactor type	Reactor model	Commercial start of operation
PFBR (unit 1)	500	LMFBR		2014
Kaiga (unit 1)	202	PHWR	Four loop	2000
Kaiga (unit 2)	202	PHWR	Four loop	2000
Kaiga (unit 3)	202	PHWR	Four loop	2007
Kaiga (unit 4)	202	PHWR	Four loop	2011
Kakrapar (unit 1)	202	PHWR	Four loop	1993
Kakrapar (unit 2)	202	PHWR	Four loop	1995
Kakrapar (unit 3)	630	PHWR	Four loop	2015
Kakrapar (unit 4)	630	PHWR	Four loop	2015
Kalpakkam (unit 1)	205	PHWR	Eight loop	1984
Kalpakkam (unit 2)	205	PHWR	Eight loop	1986
Narora (unit 1)	202	PHWR	Four loop	1991
Narora (unit 2)	202	PHWR	Four loop	1992
Rajasthan (unit 1)	90	PHWR	CANDU	1973
Rajasthan (unit 2)	187	PHWR	CANDU	1981
Rajasthan (unit 3)	202	PHWR	Four loop	2000
Rajasthan (unit 4)	202	PHWR	Four loop	2000
Rajasthan (unit 5)	202	PHWR	Four loop	2010
Rajasthan (unit 6)	202	PHWR	Four loop	2010
Rajasthan (unit 7)	640	PHWR		2014
Rajasthan (unit 8)	640	PHWR		2015
Tarapur (unit 1)	150	BWR	BWR-1/mark II	1969
Tarapur (unit 2)	150	BWR	BWR-1/mark II	1969
Tarapur (unit 3)	490	PHWR	Two loop	2006
Tarapur (unit 4)	490	PHWR	Two loop	2005

Note: BWR: boiling water reactor; LMFBR: liquid metal fast breeder reactor; PFBR: prototype fast breeder reactor; PHWR: pressurized heavy water reactor; SMR: small and medium sized reactor.

India had no developed defence or aerospace technology from which it could borrow to develop its indigenous nuclear technology. As a result, India had to develop its industrial infrastructure and regulatory framework for nuclear power building from its basic foundation. To the extent possible, India made use of existing industries to fabricate the necessary tools and components. In cases where such industries did not exist, India had to develop its own supporting infrastructure in addition to its nuclear programme.

As evidence of this capacity built up, a third pair of reactors (a second pair of PHWRs) was constructed indigenously and put into operation in 1984 and 1986.

After developing the capacity to build reactors, India began to upgrade the reactor design. As a result, India improved the initial PHWR design and indigenously developed a standardized design of 220 MW(e) PHWRs. Four additional pairs of 220 MW(e) PHWRs with improved safety features have been constructed and, thus, a final standardized design has been achieved. Moreover, the 220 MW(e) design has been scaled up to a 540 MW(e) unit, and two such units have been put into operation. A 700 MW(e) unit has been designed, and construction of the first nuclear power plants with twin 700 MW(e) units is expected to start very early in the next decade.

The experience gained in nuclear power plant construction resulted in a reduction of the construction schedule. The time period from the first pour of concrete to the first criticality decreased from 150 to 60 months. As a result, all nuclear power plants with indigenous PHWRs are currently constructed in compliance with the original schedules. Several design changes and safety upgrades consistent with international developments in nuclear technology were implemented progressively and, at times, during the construction phase, delaying the construction. However, now that a standardized design and a stable infrastructure have been achieved, the gestation time of 60 months has become the norm.

With respect to the operation of the plants, experience has shown that Indian reactors are safe and efficient. After 295 reactor-years of operation, only three minor incidents have occurred, and none of these incidents has produced radiological consequences. With regard to efficiency, Indian reactors have been run with capacity factors approaching 90%.

The Indian experience provides a success story in the role of SMRs in the development of India's nuclear power programme. The SMR technology has given India a contextually appropriate starting point from which the country can gain experience in the design, construction and operation of nuclear reactors, while simultaneously developing the necessary technological expertise, nuclear power infrastructure and robust regulatory framework. As a result, India now has a basis from which to expand, developing designs of larger reactors as it seeks to meet its ever increasing demand for electricity.

For example, in the year 1970, the Indian installed electric power capacity was only 13 000 MW(e) and evenly split between hydro and thermal power. However, India now has a centralized integrated grid with a total capacity of about 100 000 MW(e), representing about 70% of the country's electrical capacity. Accordingly, as the electrical grid can now accommodate larger reactors, the 220 MW(e) PHWR design has been scaled up to 540 MW(e), and there are plans to deploy 700 MW(e) PHWRs, as noted above. Moreover, because the electrical demand is increasing rapidly, several 1000 MW(e) LWRs have been ordered as an additional solution to the increasing energy demand.

At the time when this report was prepared, the Indian indigenous nuclear power programme envisioned PHWRs of 220, 540 and 700 MW(e) capacity, FBRs of 500 MW(e) capacity, eventually to become 1000 MW(e) via twin units, and the development and deployment of ^{233}U–Th fuel based systems. An advanced HWR of 300 MW(e), a technology demonstrator for direct use of thorium, is also planned for deployment. As the prototype FBR is prepared for startup commissioning at the end of 2013, India has actually entered stage 2 of its envisioned three stage nuclear power programme.

Additional larger LWRs of up to 1600 MW(e) capacity will be procured and constructed in the coastal regions of the country, where the amount of water for the condenser cooling of such reactors is sufficient. Maximizing the indigenous content of large capacity LWRs is currently under discussion.

As can be seen from the specified power ratings of the current and envisioned indigenous Indian nuclear power reactors, the three stage programme adopted in the country is essentially an SMR economy. Thus, SMR technology is not merely an initial transient phase of a greater nuclear programme; SMR technology constitutes a significant portion of the Indian programme itself. Owing to the fact that SMRs compete successfully with coal plants, they are profitable, particularly at large distances from the Indian coal mines. Moreover, the technology is practical because it has enabled India to develop its nuclear capacity on a modular basis, in a manner that was consistent with the Indian context and which enabled India to develop an indigenous industrial infrastructure.

In addition, India is carrying out development programmes for several innovative nuclear power reactors that fit into the SMR capacity range. These programmes are highlighted in Annex V.

3.4. PAKISTAN'S EXPERIENCE

The nuclear power programme of Pakistan provides a case study of a country that intends to construct nuclear power plants with SMR technology, initially with foreign assistance, and, in the long term, by developing its local capability. Pakistan's interest in nuclear technology dates back to the late 1950s, when the Pakistan Atomic Energy Commission (PAEC) was established with the objective of promoting peaceful uses of nuclear technology for the development of the national economy. Pakistan aims at gradual indigenization of its nuclear power programme to the optimum level in order to reduce over-dependence on imported plants and fuel, to conserve the foreign exchange component, to lower overall plant cost, and to expand the industrial and technological base. As it is short of conventional energy resources, Pakistan is keen on increasing the share of nuclear power for meeting its future electricity requirements. As of 2009, the electricity generated by commercial nuclear power plants constituted roughly 2.4% of electricity generated in Pakistan. In 1971, the 137 MW(e) Karachi nuclear power plant (KANUPP) began commissioning. Its successful functioning and the construction of a 300 MW(e) nuclear power plant (Chasma nuclear power plant; CHASNUPP) have given the country a sense of direction to plan more nuclear units in the SMR range, in a manner that would gradually lead to self-reliance. Currently, a second unit has gone into operation at CHASNUPP, and construction has begun on a third unit. More reactors to be imported from China are planned, but the status of these projects is uncertain. The SMR technology constitutes a solution for meeting Pakistan's requirements for electricity. The country has not considered a unit size larger than 600 MW(e) for candidate nuclear power plants. The least cost solution for expansion of electricity generation system predicts the installation of 18 nuclear power units of 600 MW(e) each. The geographical distribution of this nuclear capacity could be allocated with ten units in the north at the CHASNUPP site and eight units in the southern coastal area. Hence, the remote coastal areas make SMR an attractive option. CHASNUPP 4, a PWR with 315 MW(e) capacity, has already been planned in accordance with the safeguard agreements with the IAEA approved by its Board of Governors in March 2011. CHASNUPP 3 is planned to begin operation in 2016.

As listed in Table 4, at present, CHASNUPP units 3 and 4 are under construction and are expected to begin commercial operation in 2016 and 2017, respectively. Three SMR units operate in Pakistan. CHASNUPP unit 2 was connected to the grid in March 2011, and began commercial operation in May of the same year.

TABLE 4. SMRs OPERATING AND UNDER CONSTRUCTION IN PAKISTAN [2]

Nuclear power plant	Net MW(e)	Reactor type	Reactor model	Commercial start of operation
KANUPP (unit 1)	125	PHWR	CANDU	1972
CHASNUPP (unit 1)	300	PWR	CNP-300	2000
CHASNUPP (unit 2)	300	PWR	CNP-300	2011
CHASNUPP (unit 3)	315	PWR	CNP-300	2016
CHASNUPP (unit 4)	315	PWR	CNP-300	2017

Note: PHWR: pressurized heavy water reactor; PWR: pressurized water reactor; SMR: small and medium sized reactor.

The implementation of the nuclear power programme of Pakistan consists of two phases: the short term plan and the long term plan. The short term plan envisages construction of nuclear power plants with foreign assistance as quickly as possible with a view to alleviating power shortages. It is planned to purchase, when the national economy allows, proven types of commercially available plants of standard design with reasonable financing terms, ensuring full participation of PAEC and local industry for maximizing the transfer of technology. With increasing local capability for design and engineering, construction and manufacturing, it is intended to shift gradually from a turnkey or two package approach to multiple package contracts for subsequent plants. The long term plan aims at systematically developing local capability, in close cooperation with supplier countries, leading progressively to increasing indigenous design, engineering and manufacture of nuclear power plants, together with their components and fuel. The development of infrastructure facilities at the CHASNUPP site and civil construction of all plant building/structures outside nuclear and conventional islands has been carried out by local industry. In future plants, civil works will be carried out by local industry with sizeable contributions to installation. Some local manufacturing capability exists in the public and private sectors for the manufacturing of thermal power plant boiler components, heat exchangers and electrical equipment.

As it is in the process of implementing a nuclear power programme, Pakistan has to deal with the challenge of O&M, and this can be done through establishing simulator facilities. PAEC initiated a programme for the development of SMR simulators that led to the development of full scope training simulators for PHWRs and PWRs, with the objective of facilitating understanding of the dynamic behaviour of systems and subsystems of SMRs. The initial work on a simulator for KANUPP began in 1976. However, it was not until 1994 that PAEC decided, after the IAEA's proposal, to develop a full scope training simulator for the SMR CHASNUPP unit 1 that started operating in 2000. In PAEC, efforts have been made to look after instrumentation and control, materials, nuclear fuel cycle facilities and manufacture of spares for KANUPP. A full scope training simulator for CHASNUPP has been developed with the technical assistance of Chinese experts. The simulator has been used for training the plant personnel to perform their tasks and functions efficiently and for the confirmation of plant control strategies, operating procedures and plant modifications. The scope of simulation covers the energy generation and conversion cycle with associated auxiliary systems, instrumentation and control systems, protection systems, engineered safety features and electrical power distribution systems. The process of developing simulators for SMRs provided the opportunity to develop indigenous capabilities and acquire considerable experience.

Through the evolution of the nuclear power programme of Pakistan, it can be seen how a country based on SMR technology can switch from foreign assistance to the development of its own capability. Although it is expected to import more reactors from China, the country aspires to reach the point where reactors will be based on an indigenous design. In addition, the development of a full scope training simulator facilitated the introduction of CHASNUPP 1.

3.5. RUSSIAN FEDERATION'S EXPERIENCE

3.5.1. Summary of experience and future plans

The emerging SMR programme in the Russian Federation is unique in that it seeks to apply the established Russian nuclear ship propulsion technology to civil SMR applications, thereby reaping the economic benefits that have resulted from the standardized, serial production of nuclear propulsion reactors. The Russian Federation has a well developed defence industry upon which it could rely for nuclear technology. Thus, it has had the industrial infrastructure in place to develop a large nuclear energy programme that utilizes reactors of varying sizes. While the country continues to design and build LRs, it is currently developing SMRs that can be used within land based or floating nuclear power plants for remote applications. By utilizing proven technologies of the propulsion reactors originally developed for nuclear submarines and later used in icebreakers, the Russian Federation foresees that the SMR programme could benefit economically from standardized production. Should this programme prove successful, the Russian Federation may not only acquire a specific technology to offer to developing countries, it might also provide a case study on the benefits of standardizing an SMR programme to achieve production in series.

At present, there are 11 SMR units in operation in the Russian Federation, while there are 2 SMR units under construction (Table 5).

Russian nuclear propulsion reactor technology is well established. It has an experience base resulting from 8000 reactor-years of operation. Moreover, this technology has been utilized within a standardized process of serial production and installation, which has been shown to reduce costs. To document this fact, in 2003–2005, the Russian design organization Experimental Design Bureau for Machine Building (OKBM) conducted a comprehensive economic study of the propulsion nuclear plant life cycle.

The study was performed in three stages to analyse the impacts of production in series on the costs of fabrication of reactor plant equipment, of installation of reactor plant equipment and systems, and of operation, life extension and repair of the plant. The economic data for these three stages of the study were collected from manufacturers (fabrication), ship building enterprises (installation) and dockyards (repairs), respectively.

TABLE 5. SMRs OPERATING AND UNDER CONSTRUCTION IN THE RUSSIAN FEDERATION [2]

Nuclear power plant	Net MW(e)	Reactor type	Reactor model	Commercial start of operation
Beloyarsk	560	LMFBR	BN-600	1981
Bilibino	11	LWGR	EGP-6	1974
Bilibino	11	LWGR	EGP-6	1975
Bilibino	11	LWGR	EGP-6	1976
Bilibino	11	LWGR	EGP-6	1977
Kola	411	PWR	WWER-440/V230	1973
Kola	411	PWR	WWER-440/V230	1975
Kola	411	PWR	WWER-440/V230	1982
Kola	411	PWR	WWER-440/V230	1984
Novovoronezh	385	PWR	WWER-440/V230	1971
Novovoronezh	385	PWR	WWER-440/V230	1972
Akademik Lomonosov-1	30	PWR	Ship borne	2015
Akademik Lomonosov-2	30	PWR	Ship borne	2015

Note: LMFBR: liquid metal fast breeder reactor; LWGR: light water cooled, graphite moderated reactor; PWR: pressurized water reactor; SMR: small and medium sized reactor.

As a result of the study, it was determined that serial production reduces fabrication costs by 30–35% and installation costs by 20–40%. These cost reductions are shown schematically in Fig. 1, where it can be seen that the cost of fabrication and installation drops rapidly with the first few units produced and then approaches an asymptotic minimum. Apart from the costs of fabrication and installation, the OKBM study also indicated that the costs of repair drop by a minimum of 30%.

Based on a large amount of data presented in the OKBM study, the cost reductions mentioned above were analysed to reveal the following major groups of factors affecting them.

3.5.2. Factors contributing to reduction of costs

3.5.2.1. Reduction of R&D costs

Cost reductions were found to occur at all stages of the propulsion nuclear plant life cycle, including the very first one, that of R&D. The experience of OKBM in R&D of the reactor plants and the reactor plant equipment argued that the R&D costs could be reduced owing to:

- Better specialization of the involved design organizations;
- Availability of inter-industrial or State programmes and reporting to the customer;
- Use of proven technical features, and use of unified equipment items and units;
- Experimental testing of technical features on mock-ups, and broad use of mathematical modelling;
- Continuous monitoring of the current state of the production facilities, timely development of pre-production work assignments, and effective interactions and feedback between the organizations of production and operation;

— Integration of several design stages;
— Use of computer aided design and other state of the art techniques of design and test result processing.

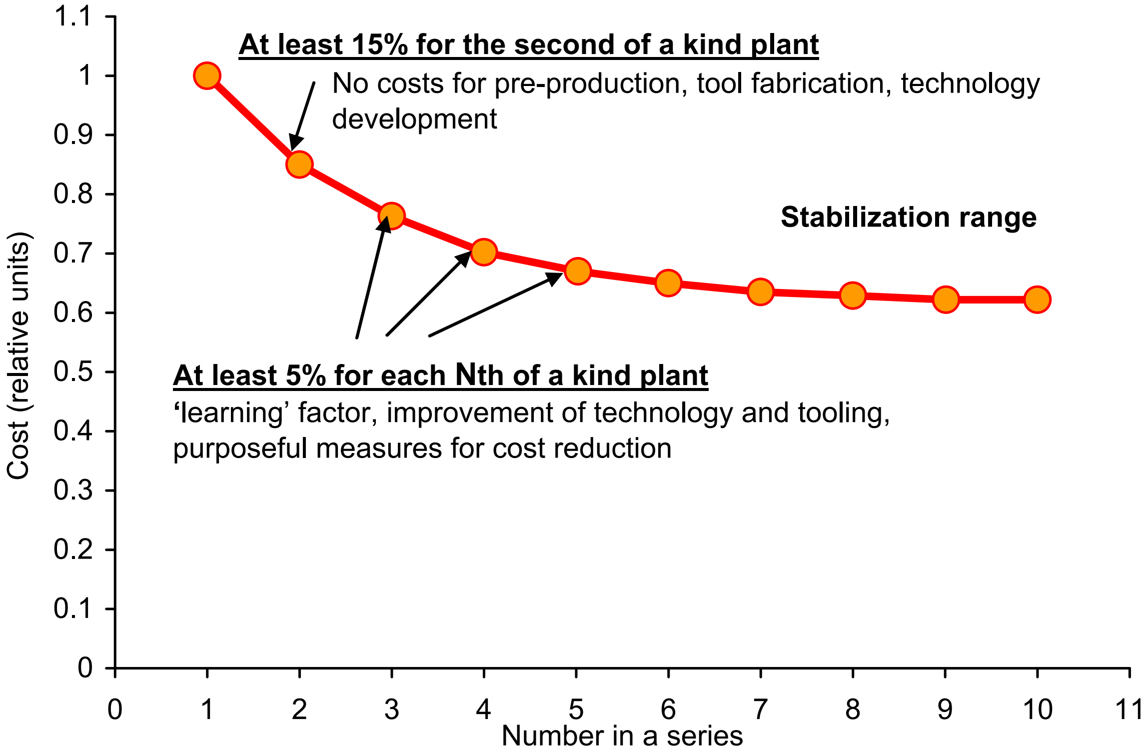

FIG. 1. Reduction of costs of equipment fabrication and installation in serial production of nuclear propulsion plants.

3.5.2.2. Reduction of commercial fabrication, installation and repair costs

The following factors facilitate a reduction of the costs of a propulsion nuclear plant fabrication, installation and repair:

- The prominent factor is State participation aimed at the fulfilment of project objectives, observation of due dates, budget limits and quality assurance requirements. State participation is manifested in:
  - Availability of a programme that specifies project objectives, expected results, work scope, schedule, customers, participants, subcontractors, funding sources and priorities for supplies and resource allocation, etc.;
  - Reasonably stable centralized funding, tax allowances, etc.;
  - Customer control over work schedule, scope and supplies;
  - Inter-industrial cooperation.
- Industry specific factors:
  - High degree of specialization of industrial enterprises in the fabrication of specific products;
  - Accumulation and analysis of existing experience, and improvement of technologies, tools, control methods, etc. provided by specialized industrial services and by the design, technology and research organizations;
  - Control over labour intensity, and policies targeted at labour intensity reduction;
  - Control over work schedules inside each of the involved industries;
  - Training programmes for staff of the involved industries.

- Overarching factors:
  - Continuity of serial production;
  - Supply and installation of the equipment in factory assembled modules;
  - Unification and standardization of technological processes, components, tools, etc.;
  - Continuity of technological processes during fabrication of a batch of serial products;
  - High production intensity and output.

As can be seen from Fig. 1, these factors for standardized serial production can lead to cost savings approaching one third of the cost for a first of a kind reactor plant.

Thus, the Russian SMR programme has the potential to offer a developed technology and to provide the economic benefits of serial production. The Russian Federation is also seeking to apply standardization and construction in series to its LRs. Consequently, a developing country could learn from this experience and plan the development of its industrial infrastructure in a manner configured to capture the benefits of standardized, serial production.

More details about the Russian experience with propulsion nuclear reactors and the OKBM case study can be found in Annex VII.

4. SUITE OF METHODS AND MODELS TO ASSIST DESIGN ORGANIZATIONS AND GUIDE POTENTIAL USERS ON THE ECONOMIC PERFORMANCE OF SMRs

4.1. INTRODUCTION

It is hardly relevant to compare a single unit SMR with a large nuclear reactor, in terms of competitiveness. In general, while large nuclear reactors have taken advantage of economies of scale, SMRs have been promoted for their advantage of being modular and to obtain benefits of factory fabrication and multiple units. The comparison should involve a nuclear option with LRs or with a series of SMRs, whichever better fits into a certain niche, and the competing non-nuclear technologies, such as gas, coal, hydro and renewables. A group of sequentially built SMRs can be compared to fewer LRs intended to yield the same aggregate power.

For conducting a comparative assessment of investment attractiveness in both cases, a number of factors affecting generation costs, revenues, financial costs and investment risks need to be taken into account. Selecting between a nuclear and non-nuclear option, and the financial planning of an energy option are comprehensively supported by the IAEA energy planning tools, as presented in Section 4.2. Section 4.3 provides a summary of simple models that can be used to assess competitive design and deployment of SMRs versus larger reactors and acts as a ‘navigation tool’ for Sections 4.4 and 4.5. Section 4.4 presents separate assessment methods and models available for the purpose identified in Section 4.3. Section 4.5 highlights the activities targeted at consolidation of the models for comparative assessment of the investment attractiveness of SMR based versus LR based projects, and presents a possible framework for such a consolidated approach. More details of the methods and models considered in Sections 4.4 and 4.5 are provided in Annexes II, III, V, VIII and IX.

Figure 2 schematically illustrates the modelling areas relevant to comparative assessment of the investment attractiveness of nuclear power plant based projects and gives links to particular sections of this report where the relevant models are presented and certain aspects of the modelling are discussed.

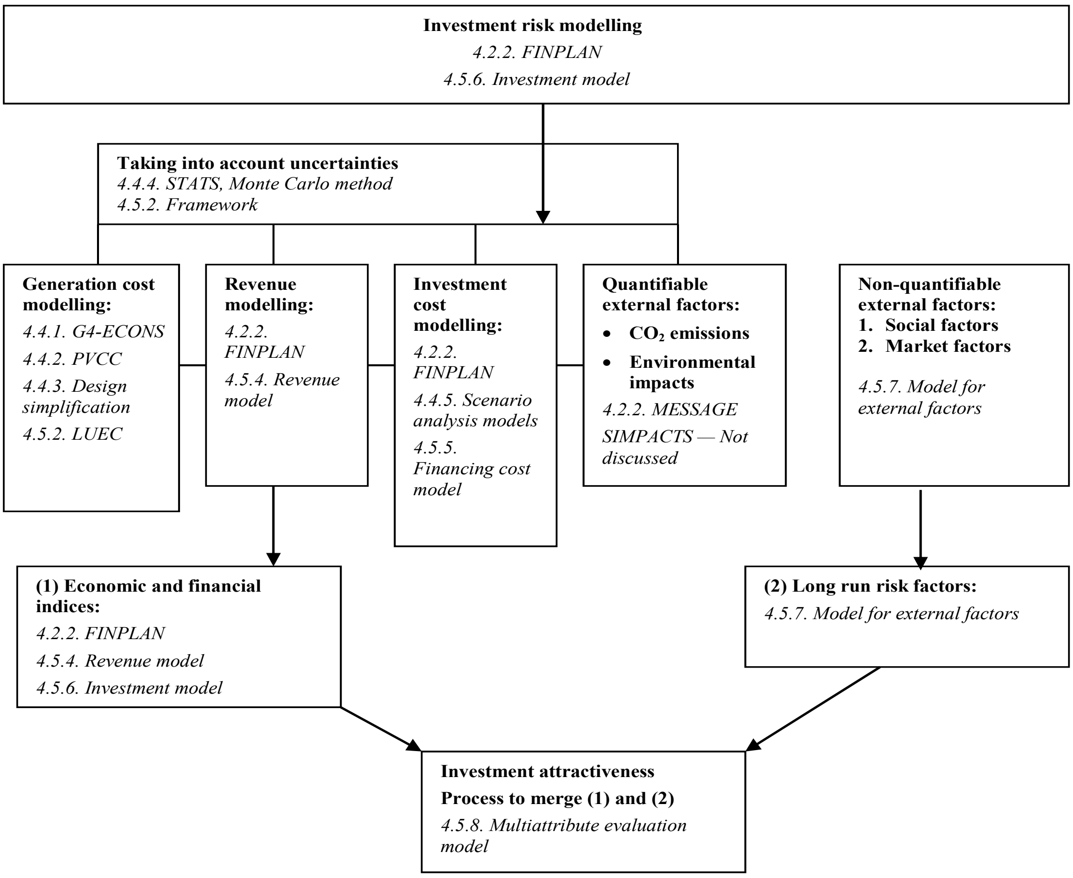

FIG. 2. Modelling areas relevant to comparative assessment of the investment attractiveness of nuclear power plant based projects (numbers in italics indicate the sections of this report where relevant models are discussed). G4-ECONS: Generation IV spreadsheet calculation of nuclear systems; LUEC: levelized unit electricity cost; PVCC: present value capital cost.

4.2. IAEA METHODOLOGIES AND ANALYTICAL TOOLS

4.2.1. Summary of the IAEA’s energy planning tools

The IAEA has developed a set of models and analytical tools that cover a wide spectrum of energy issues and provide a consistent framework for developing and evaluating alternative development paths for the energy system or a subsystem, allowing for expected changes in demography, lifestyles, technological developments and innovations, economic competitiveness, environmental regulations, market restructuring, and global and regional developments. These models are adaptable to different situations, requirements and applications in different countries. Table 6 lists the IAEA’s energy planning tools and includes aggregated numbers of total releases of these models to organizations in IAEA Member States, given separately for each corresponding model.

The models developed by the IAEA that are applicable to assess the potential role and competitiveness of SMRs are MESSAGE and FINPLAN. These models can be used interactively to conduct an integrated analysis. MESSAGE considers the full range of energy supply options together with all relevant infrastructure facilities and resources, including the capability to incorporate technical, economic, environmental, regulatory and policy constraints. It identifies an optimal portfolio of energy supply facilities that should be built/expanded over time to meet the expected future energy demand, by minimizing the total energy supply cost. FINPLAN assists in evaluating the financial viability of the investment plan determined by MESSAGE analysis. The output from FINPLAN can be used to modify the inputs to MESSAGE, if the given financial resources do not support the MESSAGE proposed investment plan. A consistent set of scenarios for the development of energy supply facilities can be modelled through an iterative procedure.

TABLE 6. SUMMARY OF THE IAEA'S ENERGY PLANNING TOOLS WITH NUMBER OF RELEASES TO MEMBER STATES

IAEA models	Releases to organizations in Member States
ENPEP — Energy and power evaluation programme	81
FINPLAN — Model for financial analysis of electric sector expansion plans	33
MAED — Model for analysis of energy demand	113
MESSAGE — Model for energy supply strategies and their general environmental impacts	83
SIMPACTS — Simplified methodology for estimating impacts of electricity generation	51
WASP — Wien automatic system planning package	116
Total number of IAEA Member States in which these models are used	126

4.2.2. IAEA models applicable to SMRs (MESSAGE and FINPLAN)

4.2.2.1. Model for energy supply systems and their general environmental impacts (MESSAGE)

MESSAGE is designed to formulate and evaluate alternative energy supply strategies in agreement with existing and future energy environmental policy objectives, capital constraints for new investments in energy infrastructures (plant and equipment), market penetration rates for new technologies, domestic energy resource availability, imports, environmental emissions, etc. MESSAGE is very flexible and can also be used to analyse energy/electricity markets as well as climate change issues. Originally developed at the International Institute for Applied Systems Analysis, the model was acquired by the IAEA, which adapted the model for energy planning purposes and added a user interface to facilitate its use.

The essence of MESSAGE is a mathematical reflection of the modelled energy system or a subsystem. A full scale application of the MESSAGE model would include primary energy resources, various energy carriers, conversion technologies[6] and end users. A simple example of an energy supply model is shown in Fig. 3.

MESSAGE provides the framework for representing an energy system with all of its interdependencies, from resource extraction (e.g. coal), imports (e.g. gas) and exports, primary conversion (e.g. coal, nuclear (including SMRs), gas and renewables), transport and distribution for different energy carriers/fuels (e.g. coal, electricity and gas) to meet the energy demands of various end users (e.g. industrial and residential).[7] The different energy forms flow through the conversion technologies, from one stage to another, before being delivered to the end users. The choice of these conversion technologies plays a vital role in determining the future development of an energy supply system.

The energy production technologies are defined by their technical and economic characteristics, for example, by their conversion efficiencies, the installed capacities, the degree of variability in production capabilities, maximum utilization rates, investment costs, construction time and O&M costs.

The model takes into account existing installations, their vintage structure and their retirement at the end of their useful life, including the possibility of rehabilitation. Supply–demand balancing is determined through an optimization process, which determines the need to construct new capacities of various technologies. Knowing new capacity requirements permits the user to assess the effects of system growth on the economy, by relating the electricity investment to gross domestic product, to evaluate the viability of the total investments.

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[6] The energy conversion technology inputs are specified as economic (e.g. cost), technical (e.g. conversion efficiencies), environmental (e.g. pollutant emissions) and sociopolitical characteristics.

[7] Demand is assumed as an exogenous variable.

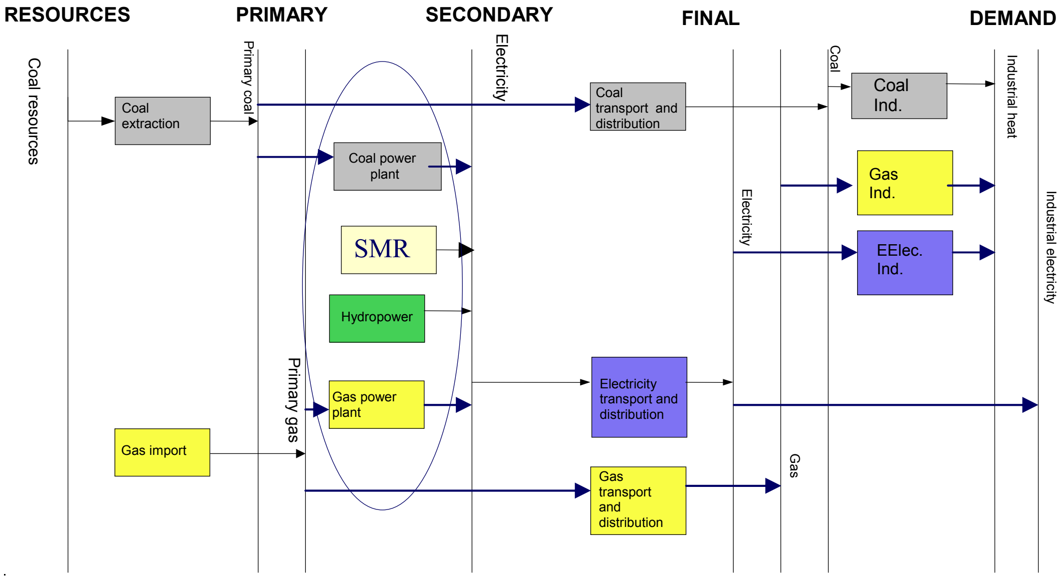

FIG. 3. A simple energy supply model in MESSAGE: physical flow. SMR: small and medium sized reactor.

Figure 4 shows a typical application of a MESSAGE package. The input, consisting of energy system structure, base year energy flows and prices, is processed in the package to predict the primary and final energy mix. The investment requirements can be distributed over the plant construction duration, and can be subdivided into different categories to more accurately reflect the requirements of industrial and commercial sectors. The requirements for basic materials and for non-energy inputs during construction and operation of a plant can also be accounted for, by tracing their flow from the relevant originating industries, either in monetary terms or in physical units.

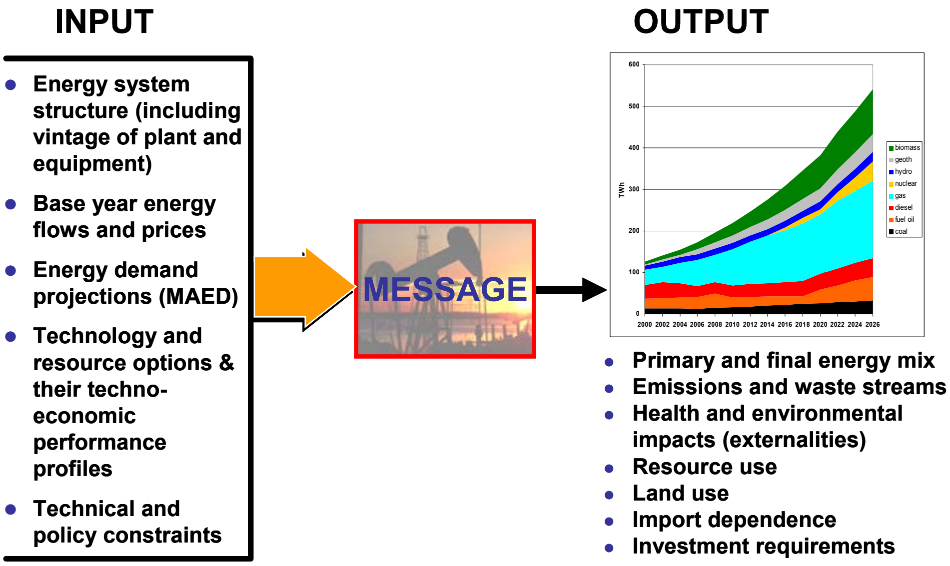

FIG. 4. A typical MESSAGE application.

For some fuels, ensuring timely availability entails considerable cost and management effort. Electricity has to be provided by the utility exactly when it is demanded. MESSAGE simulates this situation by subdividing each year into an optional number of so-called load regions. The parts of the year can be aggregated into one load region according to different criteria, for example, sorted according to power requirements or aggregation of typical consumption patterns (summer–winter, day–night). The latter (semiordered) load representation creates the opportunity to model energy storage as the transfer of energy (e.g. from night to day or from summer to winter). Including a load curve further improves the representation of power requirements and the utilization of different types of power plant.

Environmental aspects can be analysed by keeping track of and, if necessary, limiting the amounts of pollutants emitted by various technologies at each step of the energy chain. This helps to evaluate the impact of environmental regulations on energy system development.

A powerful feature of MESSAGE is that it provides the opportunity to define constraints and links between all types of technology related variables. The user could, inter alia, limit one technology in relation to another (e.g. a maximum share of wind energy that can be handled in an electricity network), give exogenous limits on sets of technologies (e.g. a common limit on all technologies emitting CO_2, which would be defined in tonnes of CO_2 per unit time or per kW(e)), or define additional constraints between production and installed capacity (e.g. ensure take or pay clauses in international gas contracts, forcing customers to consume or pay for a minimum share of their contracted level during summer months).

To run MESSAGE, the initial stage is to prepare an input dataset describing the existing supply system, the expected future demand, the available energy resources, the possible technological options and any physical or policy related constraints. The optimization algorithm incorporated into the model computes the least cost supply mix suitable to meet the demand and satisfy all of the constraints. If SMRs are included in the list of possible technologies, a given least cost solution might rule out SMRs if their competitiveness in comparison to other technologies is unfavourable. However, if there is an increase in the cost of alternatives (e.g. fossil fuel prices) or the level of pollutant emissions is unacceptable, this might change the compositions of the least cost energy supply mix, for example, by ruling out coal plants as a viable option and selecting one or more SMRs. In this case, coal will be driven out of the competition, and one or more SMRs will be selected as part of the least cost solution.

Another example can be defining a scenario with soaring gas prices during the scenario horizon that makes gas a less economically viable option, reduces its share in the least cost portfolio and results in bringing SMRs into the energy mix. In general, MESSAGE gives the user the flexibility to define multiple scenarios and evaluate their impact on the energy supply mix.

MESSAGE has been employed in many national and regional energy planning studies. For example, in the case of Lithuania, MESSAGE was used for assessment of different energy supply options. Six options were evaluated regarding the impact of the Ignalina nuclear power plant closure in 2004 and 2009 on the energy supply sector, along with associated economic and environmental implications. As a replacement of the nuclear power plant, various new generation plants were evaluated, including the combined cycle gas turbine and a 600 MW(e) SMR. The study concluded that the construction of a new nuclear plant is an economically attractive and competitive option (assuming low investment), as compared to other options that are based on fossil fuel power plants, assuming constant international oil and gas market prices through to 2025.

Similar studies have also been conducted for other countries, incorporating SMRs in their analysis, such as Ghana and Indonesia [14].

MESSAGE is an extensive model that requires pre-planning with detailed information about the existing resources and those that are to be imported. Some of the very prominent features of MESSAGE are:

- Front and back end of each fuel cycle (if applicable);
- Environmental factors such as emissions and wastes (including material accounting for spent fuel);
- Climate change mitigation options (e.g. emission trading, clean development mechanism and post-Kyoto proposals);
- Sustainable development targets;
- Security of supply concerns (absolute or relative constraints for total imported energy sources or for import shares from different supply regions);
- Technological learning to reflect innovation and improvements in economic efficiency of technologies.

4.2.2.2. Model for financial analysis of electric sector expansion plans (FINPLAN)

FINPLAN helps to assess the financial viability of plans and projects, in general, and it is particularly useful in developing countries where financial constraints are often the most important obstacle to implementing optimal electricity expansion plans. It is designed to evaluate the financial implications of an expansion plan for a power generating system, of all technology types, such as coal, gas or nuclear power, including SMRs. When an optimal or desired investment programme for system expansion has been determined, for example, with the help of the MESSAGE model, its financial plan should be developed. If the expansion plan is too ambitious for the available resources, even the most efficient (least cost) configuration may not be achievable. Such financial constraints may require a revision of the economically optimal expansion plan. FINPLAN helps to analyse alternative expansion plans by evaluating their financial consequences.

The advantage of using FINPLAN is not to facilitate in finding a better energy mix in terms of total discounted energy supply costs, rather it helps in evaluating alternatives with different investment schedules, cash flow streams, etc. The model may involve higher total system costs, but might be feasible under the given volume and timing constraints, in financing.

The FINPLAN model is designed to consider all power plants within a system or owned by a company. It can be used for the financial analysis of a single power plant. In the case of a system level analysis, the model evaluates the overall financial performance of the company, including the addition of a set of power plants, over a given time period. For a single plant analysis, it evaluates the financial viability of the plant under assumed market conditions.

As shown in Fig. 5, the information used by the model as inputs can be grouped into three types: (i) parameters specific to the expansion plan, i.e. types, sizes and timing of power plant additions, expected electricity generation by each plant, and the investment, fuel and operating costs; (ii) economic and fiscal parameters, describing assumptions on inflation, price escalation, exchange rates, prices, taxes, etc.; and (iii) financial parameters, defining financing possibilities such as fixed rate credits/loans, variable rate loans, bonds and equity.

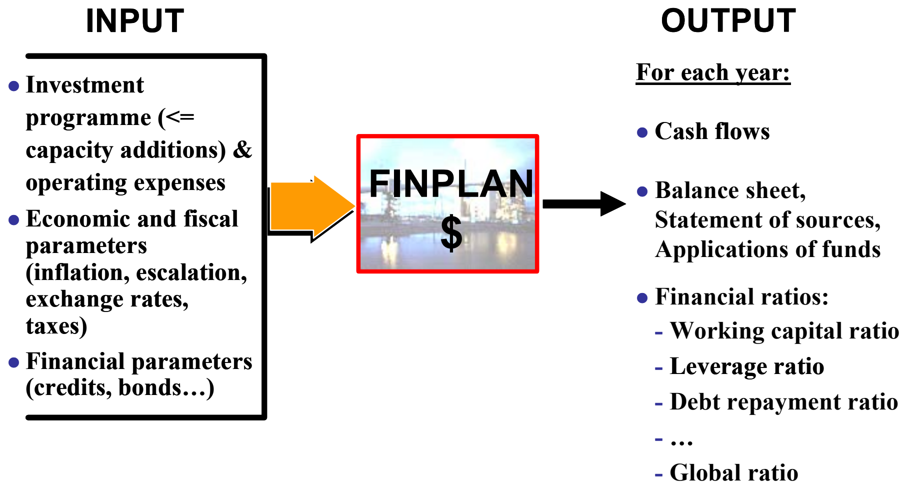

FIG. 5. Main inputs and outputs of FINPLAN.

The model outputs generated for each year can be summarized as: discounted cash flows (DCFs); various standard financial statements, such as sources and allocation of funds; current accounts of revenues and expenditures; income statements and balance sheets; and financial ratios, such as working capital, equipment renewal, leverage, gross profit rate, debt repayment time, exchange rate risk, break-even point and interest charge weight[8], which can be used as indicators for the financial status and creditworthiness of a company.

The model has five submodules: (i) investment, (ii) debt, (iii) revenue and expenditure, (iv) tax and royalty, and (v) foreign exchange. A brief explanation of each module is given below:

(i) The investment module calculates cash flows associated with ongoing and new investments in the generation, transmission and distribution systems[9];

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[8] This is the ‘relative weight of financial charges’, the ratio gives a relative weight of financial expenditures in relation to value added. For a capital intensive industry such as the nuclear industry, a ratio of 20% can be acceptable.

[9] Transmission and distribution investments can be ignored if the model is applied to a generation company.

(ii) The debt module computes cash flows based on borrowing, interest payments and loan repayments;

(iii) The revenues and expenditure module handles accounts of revenues from the sale of electricity or any other income, and all expenditures including operating expenses and dividend payments — it also calculates the depreciation charge on fixed assets;

(iv) The tax and royalty module computes income tax and royalties as well as equity repayments;

(v) The foreign exchange module calculates the foreign currency requirements for investments, purchase of imported fuels and debt service for foreign currency loans.

For developing countries, arranging funds in foreign exchange is an added difficulty. The model treats all expenditures in two currencies, one foreign and the other local. The cash flows for all expenditures in the respective currencies are maintained, and the impact of future exchange rate changes is analysed accordingly.

The model does not optimize the financing package. The user achieves financial equilibrium through an iterative process, analysing the output and revising the inputs. While this is more time consuming, it also permits a certain flexibility for creative financial proposals. The model is useful as it helps to project the future financial status of a company or the modelled segment of the power sector.

FINPLAN is not a technology specific model. It is a financial planning tool that assists in assessing the financial viability of a given energy system extension strategy. For example, the least cost expansion plan of the power sector may propose an LR of 1200 MW(e), but phased financing (self-financing, equity, loan or export credit) may only allow for a staged construction of four units of 300 MW(e) SMRs over a period of 30 years, as financing flows through. FINPLAN can be used to analyse the financial features and viability of the 1200 MW(e) LR versus four 300 MW(e) SMRs to evaluate the funding requirements and their financial implications, including the financing cost.

FINPLAN has been employed in various case studies in different countries. For example, the Pakistan planning study evaluated the finances of the least cost option of 22 units of 600 MW(e) SMRs over the entire planning horizon [15]. The investment plan for such a magnitude required substantial foreign exchange, approximately 70%. This warranted detailed financial analysis, specification of the main assumptions about investment programmes and schedule construction, inflation rates, operating cost, bulk tariff rates, depreciation rate of the plants, interest during construction (IDC), fiscal variables (tax, duties, etc.) and sources of financing. Consolidated annual and financial impacts were analysed, giving details about annual investment and foreign exchange requirements and debt servicing. To check the robustness of the plan further, sensitivity analyses of the main assumptions were performed in FINPLAN, by assuming an increase in SMR investment cost, an increase in the interest rate, foreign exchange impact or devaluation of the Pakistan rupee and a decrease in tariffs. FINPLAN has also been employed in case studies in other countries such as Poland [16].

As has already been mentioned, FINPLAN can be used in combination with the MESSAGE model to evaluate the financial aspects of the proposed energy options. Financial analysis can be conducted for a single plant or for alternative plants to select the most promising finance arrangements. FINPLAN also has some prominent features that can be incorporated into the financial plan to examine whether it will substantiate the funding of the proposed option(s). Some of these features include:

- Refurbishment/life extension of existing plants;
- Introducing private power producers;
- Different contracts for independent power producers;
- Impact of privatization and asset sale proceeds;
- Power exchanges (import/export);
- Sensitivity of electricity prices.

4.2.3. Concluding comments

MESSAGE and FINPLAN are comprehensive and well established tools available for energy expansion planning in Member States, and are capable of treating SMRs as one of the energy options. However, for developing an insight into a variety of factors affecting competitive design and deployment of SMRs, for both design organizations and potential users of such reactors, the participants of several IAEA technical and consultants meetings (see Section 1.5) recommended that additional models allowing the performance of multiple parametric studies be developed and applied, specifically for conducting comparative assessment of deployment of several smaller nuclear power plants versus fewer larger ones of the same overall capacity. Such models could guide design development of advanced SMRs from early design stages.

4.3. MODELS TO ASSESS COMPETITIVE DESIGN AND DEPLOYMENT OF SMRs VERSUS LARGER REACTORS (SUMMARY)

As technology development for SMRs is, in many cases, not completed [3, 7, 14], the relevant economic data may not be available to the extent necessary for performing comparative analyses associated with business models. This section provides a summary of models that could be used to assess competitive design and deployment of SMRs versus larger reactors and acts as a 'navigation tool' for Sections 4.4 and 4.5, where relevant models are described in more detail.

Section 4.4.1 discusses a simplified method known as the levelized unit electricity (or energy) cost (LUEC) model that yields the electricity cost in \$/MW·h. Such a methodology is presented in an example of the state of the art Generation IV spreadsheet calculation of nuclear systems (G4-ECONS) model. Because it is a simple measure, the LUEC provides a benchmark with which to compare competing reactor technologies, both among themselves and with regard to alternative energy sources. It also provides a concrete figure of merit that enters into several of the following models.

While LUEC may be useful for comparisons between single reactors, it assumes constant expenditures and production, an assumption that does not work when several reactors are being deployed one after another. To resolve the problem, LUEC models, such as G4-ECONS, incorporate elasticity factors to which certain values could be assigned individually for each individual subsequent plant to take into account the time dependent effects related to learning, on-site facility sharing by multiple units, unit timing, construction schedule and others. In a simplified way, these factors could be taken into account using the PVCC[10] model.

The PVCC model, presented in Section 4.4.2, was developed to capture the economic benefits of the effects of accelerated learning, timing, sharing and construction schedule, associated with an incremental capacity increase. This model could be used together with G4-ECONS whenever deployment of several nuclear power plants is the subject of an economic assessment. Design simplification, potentially achievable with reactors of smaller capacity, could be an important factor for improving SMR competitiveness. To facilitate the assessment of different design options, Section 4.4.3 presents the cost feature scaling model, which is a simple screening method for assessing various SMR design concepts resulting from the simplification of larger, more complex systems. By using such a screening method, the various SMR concepts can be ranked with a minimum of computational effort, allowing detailed design analyses to focus on the more highly ranked design concepts. In the described screening method, LUEC is used as a figure of merit.

Section 4.4.4 provides a generic discussion of taking into account the uncertainties in input parameters when calculating an economic figure of merit. The uncertainties may be taken into account by assigning probability distribution functions (PDFs) to input parameters and then employing a Monte Carlo random number generator to generate random values of each of the input variables. Such calculations may help better capture the complexity and ambiguity of the real world, allowing intelligent choices to be made between alternate technological options or technologies with account of possible changes in important boundary conditions over the plant lifetime.

Section 4.4.5 discusses scenario analysis models based on dynamic simulation of material flows and intended for the analysis of large evolving energy systems over long periods of time.

Each of the Sections 4.4.1–4.4.5 end with a short conclusion summarizing possible applications and limitations of the models. Models and methods discussed in these sections are presented in more detail in Annexes II, III, V, VIII and IX.

Even a brief survey of the methods and models highlighted here proposes an idea of developing a consolidated approach to the application of all relevant assessment models in comparative studies of competitive deployments of SMRs versus LRs. A possible framework of such a consolidated methodology is highlighted in Section 4.5, based on the developments ongoing in IAEA Member States. The presented framework (referred to as an 'open' model)

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[10] PVCC is an average capital cost value achieved in deployment of several reactors in series, taking into account all effects associated with building the capacity incrementally.

seeks to eventually incorporate all methods and models relevant to the assessment of SMR competitiveness in different applications within a single methodological framework.

More details of the ‘open’ model and its development status are provided in Annex VI.

4.4. MODELS TO ASSESS COMPETITIVE DESIGN AND DEPLOYMENT OF SMRs VERSUS LARGER REACTORS (DESCRIPTIONS AND DISCUSSION)

4.4.1. The G4-ECONS economic evaluation methodology for Generation IV reactor systems

4.4.1.1. Description of G4-ECONS

In 2004, the Generation IV Economic Modelling Working Group (EMWG) commissioned the development of a Microsoft Excel based tool capable of calculating the LUEC in \$/MW·h for multiple types of nuclear energy systems, i.e. reactors and associated fuel cycles, being developed under the Generation IV International Forum (GIF) programme. This overall modelling system is now called G4-ECONS, and is being expanded to calculate the costs of other energy intensive products, such as nuclear produced hydrogen and desalinated water. A version has also been developed to evaluate the costs of products or services from fuel cycle facilities. The cost estimating methodology and algorithms are explained in detail in the Generation IV Cost Estimating Guidelines [17] and in the G4-ECONS User’s Manual [18].

Each subsection of the reactor economics model computes a component of the total LUEC, which can be divided into four life cycle components: (i) recovery of capital (including financing costs), (ii) non-fuel O&M costs, (iii) fuel cycle costs, and (iv) annual funding of decontamination and decommissioning (D&D) costs via an escrow fund. All costs are calculated on a constant dollar, levelized annual cost basis, and it is assumed that capital and financing costs are repaid over the operating life of the plant. Annual electrical production is also considered to remain constant over the life of the plant. Each component of the LUEC is calculated by dividing the annualized cost (million \$/a) for that component by the annual electrical production (MW·h/a). An average capacity factor is also assumed over the life of the plant to relate electrical energy production (plant performance) to the net installed capacity of the plant.

Figure 6 illustrates the concept of levelization that is central to this type of economic modelling. The left hand side of the figure shows how typical cash flows (million \$/a) actually occur over the life cycle of a power plant. During the design/construction phase, annual costs rise to a peak and taper off into the startup phase. Annual O&M and fuel costs are nearly constant (assuming constant dollar costing), with an occasional blip for a major capital replacement item such as a steam generator. At end of life, there is another blip for the D&D costs of the plant. Power production also has ramp up and ramp down periods.

For actual power plant projects, utilities typically use business models where such detailed annual cash flows and annual power production (revenue stream) projections are entered into a complex spread sheet in order to calculate revenue requirements and project financing requirements. For technology comparison purposes, however, such as the Generation IV applications, the detailed cash flow models mentioned above are too complex, as the input data do not yet exist at a fine enough level of detail to support the business model type of forecasting. For this reason, G4-ECONS was designed to treat the costs in a levelized manner, as shown on the right hand side of Fig. 6.

Essentially, all front end costs (design, construction, startup and financing) are rolled up into a total lump sum capital cost (TLCC). This TLCC is then recovered over the life of the plant by means of a capital recovery factor, which, in turn, depends on the assumed interest or discount rate. The reverse of the capital recovery algorithm (a sinking fund equation) is used to recover the future D&D cost over the plant operating life. Other annual costs, such as fuel, non-fuel O&M and capital replacements are calculated or entered into the model as average values (typically, in million \$/a) that are the same over all years of the operating life. An average assumed power production also has a constant value over the plant operating life and represents the revenue to the utility. It is understood that this simpler representation of economics could minimize the amount of data that the project proponents must develop during the R&D phase of the Generation IV or other programmes targeted at the development of advanced nuclear reactors. However, in the limitations of the model, it may be mentioned that the sensitivity of results to assumptions about the discount rate is considerable, and that is why time dependent discount rates need to be taken into account for obtaining a more realistic evaluation.

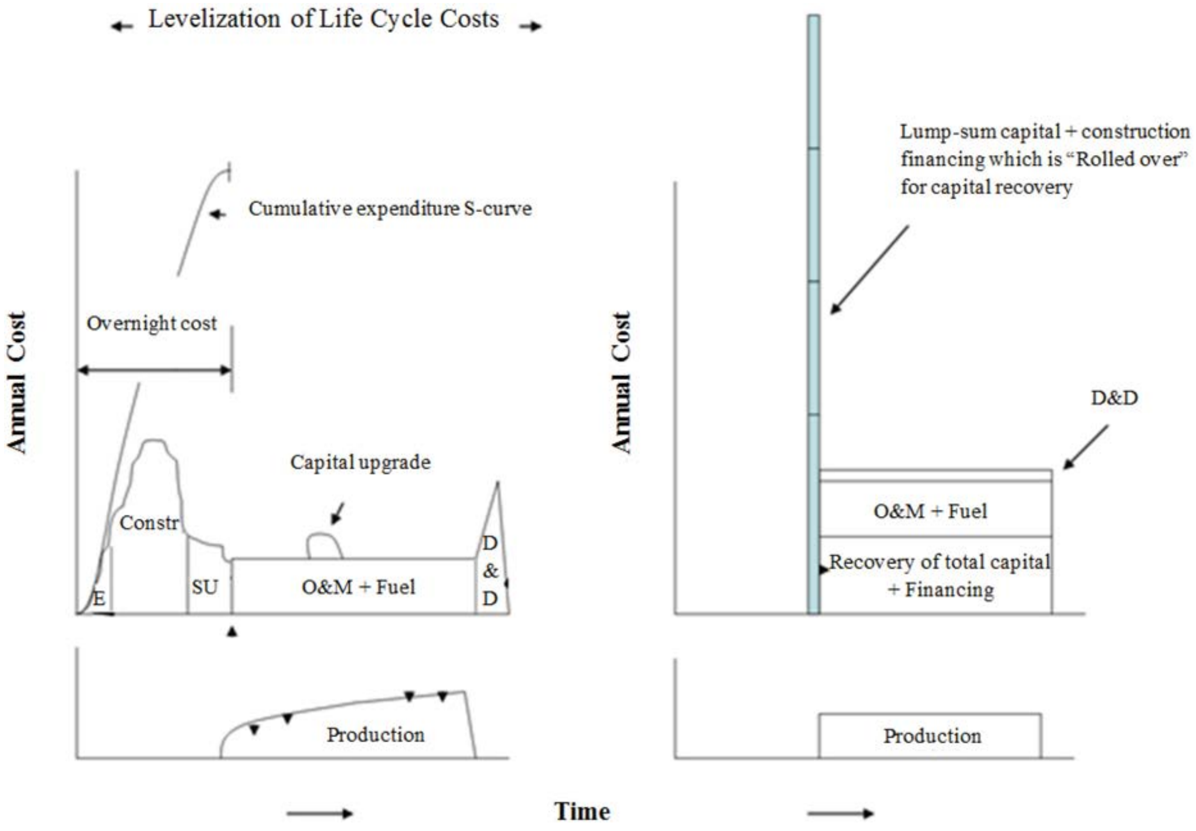

FIG. 6. Concept of cost levelization. D&D: decontamination and decommissioning; E: bid selection; O&M: operation and maintenance; SU: commissioning.

To calculate the TLCC, it is necessary to work upwards from the various cost components. The base cost is the sum of direct costs, indirect costs and owner's costs. The direct costs include civil, nuclear island, electrical, heat management and other subsystems. The indirect costs include management and services, and the owner's costs include costs such as those of startup and training. If the cost of contingencies is added to these three components of the base cost, the overnight cost is obtained.

The cost of contingencies is added to anticipate unknown factors and progressively diminishes as the design becomes more definite. As interest begins to accrue as each increment of the overnight cost is borrowed, the sine wave approximation of the overnight costs allows calculation of IDC. This interest cost is added to the overnight cost to obtain the TLCC, which is the tall shaded area in Fig. 6. The annual capital cost (ANNCAP) is then obtained by determining the value of a series of annual payments over the life of the plant, which has the same present value as the TLCC.

In a similar, though less complicated way, the annual D&D cost (ANNDD) can be obtained by determining the value of a series of annual payments to an escrow fund that would have the same future value as the projected D&D costs incurred at the end of the project.

The non-fuel O&M costs (ANNOM) include such categories as staffing, regulation, maintenance and overheads. The manner in which numbers are fed into these categories is highly subjective.

The annual fuel cycle cost (ANNFC) is the most complex part of the G4-ECONS model. When development of G4-ECONS began, it was realized that the amount of detailed fuel cycle information that the EMWG of the GIF would receive from the Generation IV development teams was likely to be very small. It was soon realized that many steps in some advanced fuel cycles, particularly those that involve fuel recycling or actinide partitioning/transmutation, are not commercially available, and that for such systems, new fuel cycle facilities involving new processes would have to be designed, built and operated. There would be no information readily available on prices, process losses, timing of purchases or even optimum facility size for many steps. It became apparent that the best option for both the Generation IV programme and the advanced fuel cycle initiative [19] was to develop snapshot in time models based on projected fuel material balances for the reactor systems of interest.

Following this approach, the modeller could, for example, take an equilibrium fuel cycle and divide it up into definable fuel cycle steps for which unit cost information is available or derivable. The complexity of these fuel calculations may be seen from an examination of the following factors that enter into the fuel cost:

- Fissile/fertile materials used (natural uranium, low enrichment uranium, highly enriched uranium, mixed oxide (MOX) fuel, uranium–thorium, etc.);
- Enrichment of fissile materials;
- Other materials in the fuel assemblies (zirconium, graphite, etc.);
- Services required to produce the required materials (e.g. mining, milling, conversion, enrichment, fabrication);
- Costs of spent fuel disposal or reprocessing, and costs of low and high level waste (including transuranic waste) disposal;
- Storage of critical materials.

G4-ECONS has the capability to calculate the ANNFC for three types of fuel cycle. These are an open fuel cycle with no recycle and planned repository disposal of the spent fuel, partial recycle in which the uranium and plutonium are recycled to produce MOX fuel assemblies, and total recycle for FBRs, in which make-up uranium is fed to the system to account for the fission products removed.

Once the annual costs have been obtained for capital recovery (ANNCAP), D&D (ANNDD), non-fuel O&M (ANNOM) and fuel cycle (ANNFC), it is then possible to calculate the levelized equivalents by dividing these annual costs by the annual energy production (ANNENERGY). For instance, if the net electrical power of the reactor and the capacity factor are known, the annual energy production in MW·h can be obtained by multiplying these two numbers together and then multiplying their product by 8766, the number of hours in a year. Dividing ANNCAP, ANNDD, ANNOM and ANNDD by ANNENERGY yields the levelized costs — levelized capital cost (LCAP), levelized D&D cost (LDD), levelized O&M cost (LOM) and levelized fuel cycle cost (LFC), all in units of $/MW·h. The sum of these last four numbers yields the LUEC.

By 2009, the G4-ECONS model had been tested on the following systems for which cost input was available: the System 80+ PWR, a Massachusetts Institute of Technology design for a pebble bed modular reactor, and the Japanese sodium cooled fast reactor (JSFR).

The System 80+ case and the JSFR case were run with other more complex generation cost models, and good agreement of the output results was found when the same input values were submitted to each model.

More details about the G4-ECONS model and the results of its testing are provided in Annex IX.

4.4.1.2. Summary

LUEC is an established figure of merit used in many models intended for the assessment of economic characteristics of power plants. An LUEC is a simplified measure in that it assumes constant expenditure and production profiles over a plant's lifetime, and is based on accordingly averaged values of other parameters, such as capacity factor or interest rate.

G4-ECONS is the state of the art model for LUEC calculation, capable of calculating LUEC in $/MW·h for multiple types of nuclear energy systems, i.e. reactors and associated fuel cycles, and is being expanded to calculate the costs of other energy products, such as hydrogen and desalinated water. G4-ECONS has been developed for cost calculations for advanced reactors that are still lacking detailed economic data. In the absence of exact input data, G4-ECONS allows the user to evaluate the relative costs of competing technologies, as well as to optimize these technologies in the design stage.

Whenever incremental capacity increase is considered, the assumptions of constant expenditure and production profiles are challenged. To capture the associated economic effects of learning, on-site facility sharing, unit timing and construction duration reduction, the LUEC model can be applied individually to each subsequently built nuclear power plant, or the corresponding factors need to be taken into account externally and introduced into the LUEC calculation as elasticity factors. The PVCC model discussed next could be applied to take such factors into account. An LUEC model is presented in this report as an available option for assessing the economic characteristics of power plants, and it is left to the discretion of Member States to decide whether to use it for conducting an economic competitiveness assessment of SMRs.

4.4.2. The PVCC model

4.4.2.1. Description of the model

Many of the features of SMRs may provide inherent advantages for application within energy markets. These advantages range across the areas of plant cost and financing, and fit with utility and country circumstances. The PVCC model was developed as part of a plant capacity and timing decision model, described in Annex VIII. In the decision model, the three factors influencing the overall decision criteria are: (i) cost, (ii) financing, and (iii) utility and country circumstances. The PVCC model presented here addresses specifically the area of cost (overnight capital cost (OCC)) and financing (only for total capital investment cost). Provisions of the model in other areas are presented in Annex VI.

A main proposition of the PVCC model is that cost savings could be available in a number of different areas related to the smaller size of SMRs. These areas are the following.

Multiple units and learning

As more than one SMR is required to provide the same total plant capacity as an LR plant, savings to the overnight cost of units after the first one can be achieved because of multiple unit and learning curve cost savings. Each of the additional units will have an overnight cost lower than the first unit since there are some fixed, non-repeatable costs incurred in the first unit. Other advantages to the deployment of multiple units at a single site are the sharing of infrastructure and better utilization of site material and human resources. These savings reduce the average cost of multiple units built on a single site or on multiple sites within a larger construction programme.

Plant design and modularization

Overnight costs can be further reduced to the extent that plant design organizations are able to achieve more cost efficient designs with design concepts that are currently possible only at smaller power levels. These cost savings may result from: (i) simpler, fewer and less complicated components (e.g. integral equipment design); (ii) alternative safety system approaches (passive safety systems, ‘safety by design’ approach); and (iii) a greater degree of modularization and factory fabrication. These cost reductions are specific to individual SMR designs and design concepts.

Construction schedule

Smaller physical plant sizes may be constructed with shorter construction schedules. For a given commercial operation date (COD), shorter schedules, with relatively later expenditures closer to the COD, result in lower total capital investment costs because of lower costs for IDC.

Unit timing

Meeting a requirement for power with multiple SMRs built over an appropriate time frame can spread out the capital expenditures over time and result in much later expenditures than can be achieved by meeting it in one large block. This delay in capital expenditures could substantially reduce the present value cost of the investments involved.

Finally, economy of scale is a traditionally mentioned factor contributing to higher specific capital costs of smaller reactors. Economy of scale results in higher per kW(e) costs of some components and systems of scaled large reactors (SLRs) relative to larger reactors if those components and systems are scaled down versions of larger reactor designs. However, as mentioned above, some SMR designs may eliminate the requirement for certain components and systems required in larger reactor designs, and many of the remaining components and systems could be based on significantly different design concepts and approaches.

The PVCC model is a generic model taking into account the following factors (described above): (1) economy of scale, (2) multiple units, (3) learning, (4) construction schedule, (5) unit timing, and (6) plant design. Figure 7 illustrates the relationship of these six factors in deriving a comparison of the relative cost per kW(e) of SMRs with that of LRs.

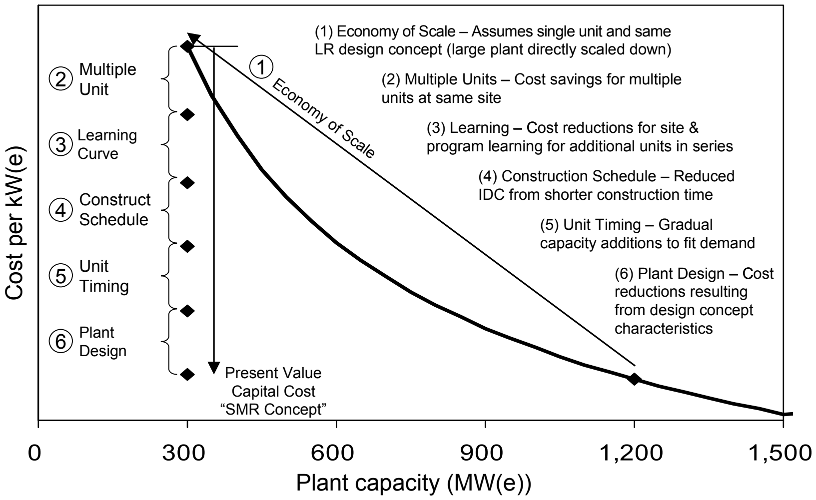

FIG. 7. Generic view of factors affecting comparative costs of small and medium sized reactors (SMRs) and large reactor (LRs). IDC: interest during construction.

It should be emphasized that Fig. 7 only gives a generic view of the factors affecting comparative costs of SMRs and LRs, when the target is to achieve the same overall capacity of a power station. In reality, the relative magnitudes of these factors may vary broadly, and should be determined on a case by case basis.

4.4.2.2. Test case with calculated results

Table 7 presents the input assumptions used in the test case. The four unit SMR plant (SMR-4) is assumed to provide the same total capacity as the single unit LR plant with each unit at one quarter of the capacity of the LR unit. The SLR cost assumes a hypothetical plant design based entirely on the LR design and scaled to one quarter capacity. The SMR-4 unit timing is assumed to match the load growth that requires the equivalent of one SMR-4 every 9 months. A representative design cost saving of 15% is assumed as the nominal case for a generic SMR. A discount rate of 5% per year is used for all results.

For the test case of Table 7, the PVCC factors were defined as described below.

TABLE 7. ASSUMPTIONS FOR MODEL EXAMPLE — TEST CASE

SMR-4 to large reactor size ratio	1:4
Scaled large reactor cost	Based entirely on large reactor design scaled to 1:4 ratio
SMR-4 unit timing	Every 9 months
SMR-4 design cost savings	15% assumed savings
Discount rate	5% per year

Note: SMR: small and medium sized reactor.

Economy of scale

The first factor represents the economy of scale, assuming that the two plants are comparable in design and characteristics. The typical correlation is given by:

$$\mathrm{OCC}_{\mathrm{SMR}} = \mathrm{OCC}_{\mathrm{LR}} \times \left(\frac{\mathrm{size}_{\mathrm{SMR}}}{\mathrm{size}_{\mathrm{LR}}} \right)^{n-1} \tag{1}$$

where $n = 0.6$. This factor determines a hypothetical overnight capital cost estimate of a single LR design that is scaled in its entirety to one quarter of the size. In this case, the overnight capital cost per kW(e) of the SLR would be 74% higher than for the LR of actual size.

Multiple units and learning

The site multiple units factor was evaluated considering that there are fixed, non-recurring costs incurred only for the first unit and that there are costs which are shared by the multiple units.

The learning factor considered was an ‘on-site’ type factor; it was evaluated from the various models reported in the literature (e.g. Generation IV) [17]. It was found that for the four unit case, the cost reduction is between 8 and 10%. The 8% value was conservatively chosen.

The combined impact of multiple units and learning was assumed to yield a 22% reduction in overnight capital cost for a four unit SMR-4. This number was defined to be consistent with Korean and French experiences reported in the literature for series builds of multiple units on the same site or multiple sites within the same standard plant programme (Annex VIII).

Construction schedule

The effect of the construction schedule was evaluated assuming a construction schedule for the LR and SMR of 5 and 3 years[11], respectively, and calculating the total capital investment cost for the two cases. This shorter construction time results in a 5% saving for SMRs.

Unit timing

The LR and the first SMR unit were assumed to go into operation on the same date. The remaining three SMRs were assumed to begin operation every 9 months thereafter. The relatively later capital cost expenditures for the SMR reduce the PVCC by an additional 5% compared to the LR. The unit timing savings on PVCC increase as the time between units matching load growth is increased. At 24 months, the savings would increase to 12%.

Plant design

The level of overnight capital cost savings achieved by the application of improved design concepts for SMRs is highly dependent on the specific SMR design and that of the LR reference. The elimination of plant components and systems in combination with more compact plant layouts could result in significant SMR cost reductions.

Cost savings of 15% were assumed for the test case.[12]

Combined capital cost results

When the various factors are combined, a pack of four SMRs has a 16% higher overnight capital cost, a 9% higher total capital investment cost (in which interest on the capital is included), and only a 4% higher PVCC than a single LR with the same total capacity (Table 8).

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[11] Typical values mentioned for many advanced LRs and SMRs [3, 4].

[12] A typical value mentioned for a PWR with integrated design of the primary circuit [8].

TABLE 8. RESULTS FOR THE TEST CASE OF TABLE 7

Capital cost factor	Capital cost factor ratio (cost of SMR/cost of LR)		
	Overnight capital cost	Total capital investment cost	Present value capital cost
(1) Economy of scale	1.74	1.74	1.74
(2) Multiple units + (3) Learning	0.78	0.78	0.78
(4) Construction schedule	n.a.	0.94	0.94
(5) Unit timing	n.a.	n.a.	0.95
(6) Design specific factor	0.85	0.85	0.85
Cumulative total	1.16	1.09	1.04

Note: LR: large reactor; n.a.: not applicable; SMR: small and medium sized reactor.

4.4.2.3. Summary

The PVCC model allows the assessment of various factors affecting the effective (present value) capital cost when several nuclear power plants are being built in a sequence. The factors included in the model are: (1) economy of scale, (2) multiple units, (3) learning, (4) construction schedule, (5) unit timing, and (6) plant design. The factors assessed by the PVCC model would be important if a deployment of several SMRs versus fewer LRs were considered. The PVCC model could be viewed as complementary to an LUEC model, such as the G4-ECONS model described previously, in that the PVCC output could be used as an input (the elasticity factor) in G4-ECONS. The PVCC application is not limited to comparative assessments of SMRs versus LRs. The model could be useful in all cases when a sequential deployment of several serial nuclear power plants is considered, irrespective of the nuclear power plant size. The methodology has been reviewed by the IAEA; however, the IAEA is in no position to endorse the use of any methodology, and the Member States need to decide whether to use the model to assess SMRs against LRs.

4.4.3. Model for systematic assessment of reduced design complexity

4.4.3.1. Introduction

The competitiveness of an SMR can be improved when its design complexity is reduced against the corresponding scaled down LR. A model to assess the impact of plant simplification on the specific overnight capital cost may assist the designer of an SMR in the definition of a consistent strategy regarding plant design, starting from early design stages. Here, such a model is presented, making reference to Annex II where more details of the model and its application are given.

4.4.3.2. Simplified screening method

As a nuclear power plant is a complex system with a high degree of component interdependence, the direct cost savings achieved by a design simplification may be offset by the costs of the necessary adjustments to certain dependent components. Therefore, the economic effect of a single design change (e.g. targeted at design simplification) would be defined by the resulting changes in all dependent design components. As careful tracing of all interdependent design changes is complex and expensive, many possible design modifications might happen to be a priori excluded from the analysis, substantially limiting the range of options considered. To include a greater variety of options, a simplified screening model may be built, which avoids the expenses of a thorough analysis, but retains a sufficient complexity to track the interdependent design effects, so that various design options can be intelligently ranked. Such a screening model could be obtained by relating the following four elements:

(a) A competitive target (or figure of merit) such as the LUEC that is required to compare the various options.
(b) A detailed feature cost scaling model, which is required to track the impacts of design changes on the main design variables of the proposed design alternatives. As an example, it may be necessary to know how the condenser size and condenser cost scale with thermal power.
(c) A set of cost multiplication factors $K_{i,j}$ that give the new cost of a modified feature (feature *i,j*) as the product of its initial cost and the factor itself.
(d) A model that relates the design features and their associated costs to both the scaling variables (such as thermal power) and the figure of merit (LUEC).

Figures 8 and 9 show how the above mentioned four elements could be combined into a single screening method. As shown in Fig. 8, a given design change d_k would affect various components of the competitive target (LUEC). Here, external values are those not under the control of the designer but which affect the cost, such as the interest rate. Project values, in contrast, include those items that are internal to the design process, but which are more general, such as plant lifetime and investment flow. To avoid cluttering of Fig. 8, cost components such as D&D costs are not shown.

For each of the components of the competitive target shown in Fig. 8, it is then necessary to trace the effects of a given design change in more detail. Figure 9 illustrates how this could be accomplished for overnight costs.

While Fig. 9 will be explained in more detail below, the purpose of the figure is to show that the overnight costs are affected both directly, by the envisioned effects of a given design change, and indirectly, through feedback effects. The direct effect is captured by the cost multiplication factor $K_{i,j}$, which multiplies the initial cost $I_{i,j}$ of item *i,j*. The feedback effects are captured through the impacts of the design change d_k on various physical variables V_n (such as reactor power) that, in turn, affect certain scaling variable combinations $V_{i,j}$ (similar to dimensionless parameters) that, in turn, scale the various item costs $I_{i,j}$. The double summation accounts for the fact that there are three basic groups of items $I_{i,j}$ with N_i items in each group.

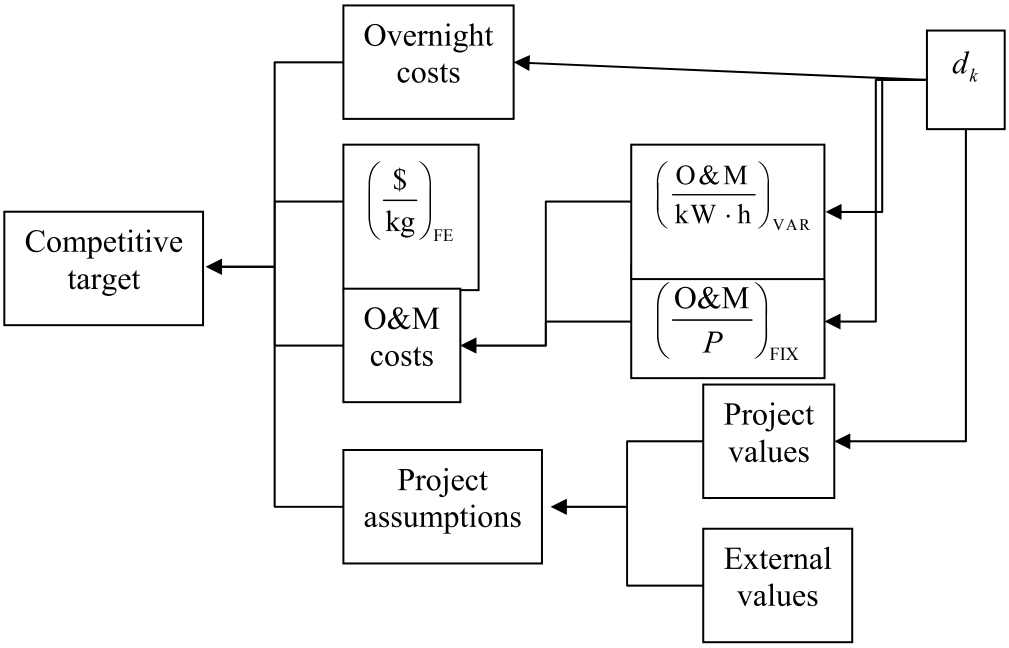

FIG. 8. Schematic flowsheet illustrating the overall competitive target calculation for a single design change d_k. FE: fuel costs; FIX: fixed; O&M: operation and maintenance; P: unit power; VAR: variable.

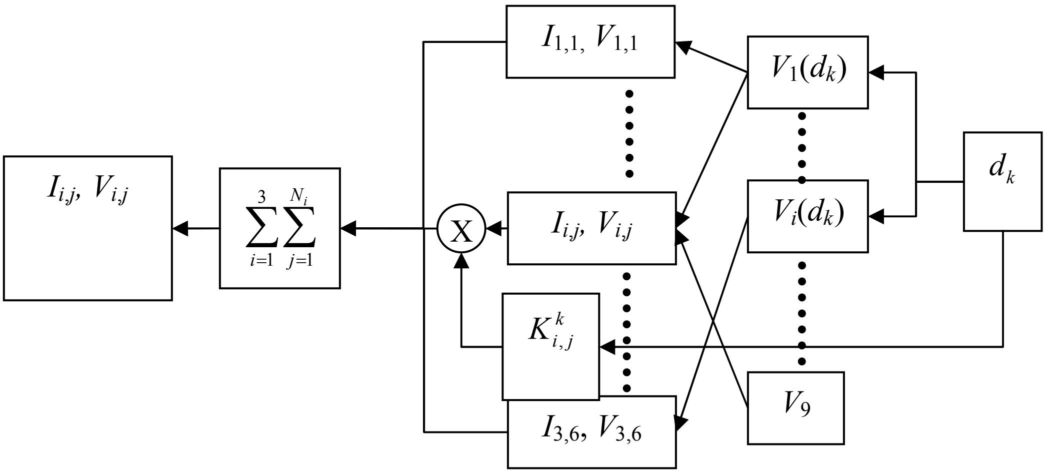

FIG. 9. Schematic flowsheet of the changes in the item cost break-down induced by a single design change d_k.

In addition to the overnight costs, the procedure shown in Fig. 9 needs to be repeated for the other cost components shown in Fig. 8, such as the O&M costs, and also for some that are not shown, such as the D&D costs.

The four elements included in the overall approach shown in Figs 8 and 9 are explained in more detail below.

4.4.3.3. Competitive target or figure of merit (LUEC)

At the top level, the expression for LUEC may be written as follows:

$$\text{LUEC} = \text{LCAP} + \text{LOM} + \text{LFC} + \text{LDD} \tag{2}$$

$$\text{LCAP} = \text{ANNCAP/ANNENERGY}$$

$$\text{LOM} = \text{ANNOM/ANNENERGY}$$

$$\text{LFC} = \text{ANNFC/ANNENERGY}$$

$$\text{LDD} = \text{ANNDD/ANNENERGY}$$

where

ANNCAP	is the annual capital recovery cost;
ANNOM	is the annual non-fuel O&M cost;
ANNFC	is the annual fuel cycle cost;
ANNDD	is the annual payment to the D&D sinking fund;

and ANNENERGY is the electrical power production in kW·h/a.

More details about the LUEC are provided in Annex II.

4.4.3.4. Feature cost scaling model

The feature cost scaling model can be explained in the example of features associated with the overnight capital cost, with reference to Fig. 10. To build such a model, it is necessary to divide the overnight cost into a simplified set of major cost components and then relate these cost components to the scaling variables. The components of the overnight cost could be divided into three major groups consisting of those features that are common to power plants of any type (group 1), those that pertain specifically to nuclear power plants (group 2), and the indirect costs of plant construction and startup (group 3). A simplified list of the main features is given in Table 9, with more details provided in Annex II.

TABLE 9. MINIMUM LIST OF ITEMS AND FEATURES FOR FEATURE COST SCALING ANALYSIS

Group No., item or feature No.	Item or feature
1, 1	Conventional buildings
1, 2	Turbogenerator system
1, 3	Electrical systems (excluding the generator)
1, 4	Condenser or heat transfer to heat sink
1, 5	Other miscellaneous equipment
2, 1	Containment or confinement
2, 2	Reactor vessel
2, 3	Control rods
2, 4	Primary to secondary heat exchangers (steam generators)
2, 5	Spent fuel management
2, 6	Instrumentation and control
2, 7	Coolant management and control
2, 8	Primary pumps or compressor, pressure regulation system
2,9	Other reactor equipment
3, 1	Special equipment for reactor mounting
3, 2	Engineering costs
3, 3	Fixed indirect costs
3, 4	Indirect conventional costs
3, 5	Indirect nuclear costs
3, 6	Other indirect costs

The overnight cost $\mathrm{CO}_{\mathrm{ON}}$ could then be obtained by summing over all of the feature costs $I_{i,j}$ for each of the three groups in Table 9, if the interest costs are not taken into account:

$$\mathrm{CO}_{\mathrm{ON}} = \sum_{i=1}^{3} \sum_{j=1}^{N_i} I_{i,j} \tag{3}$$

To have a complete scaling model, each of these feature costs needs to be modelled in relation to those reactor scaling variables that affect the associated item. A minimum list of such variables is given in Table 10. It is clear that each of these variables would not affect each of the feature costs. The list also does not include all of the scaling variables that could be identified. Rather, the list is compiled to be detailed enough to analyse the effects of different design alternatives, yet short enough to facilitate quick computation.

TABLE 10. MINIMUM LIST OF SCALING VARIABLES FOR FEATURE COST SCALING ANALYSIS

Variable No.	Scaling variable
1	Thermal power (MW(th))
2	Thermal efficiency (%)
3	Power density (MW(th)/t HM)
4	Reactor vessel weight (t)
5	Primary to secondary heat exchanger weight (t)
6	Volume of the primary system (m^3)
7	Number of fuel elements
8	Core length (m)
9	Primary pump power (MW(e))

Note: HM: heavy metal.

With the major cost features and scaling variables listed in Tables 9 and 10, the next necessary step is to relate them. In general, a feature cost $I_{i,j}$ is related to a combination of the scaling variables $V_{i,j}$ through the following scaling equation:

$$I_{i,j} = I_{i,j}^{0} \times \left(\frac{V_{i,j}}{V_{i,j}^{0}} \right)^{\gamma_{i,j}} \tag{4}$$

In this equation, $V_{i,j}$ is a combination of the scaling variables appropriate for the scaling of a cost feature *i,j* and γ is the scaling coefficient. As an illustration, let us assume that the size, and hence the cost, of a condenser scales with the thermal power rejected to the environment. The rejected power, in turn, is determined by two of the scaling variables, the thermal power P_{th} and the thermal efficiency η. In Table 9, the condenser is item 1,4 and, in Table 10, the thermal power and efficiency are variables V_1 and V_2, respectively. Then, the scaling parameter for the condenser $V_{1,4}$ would be:

$$V_{1,4} = V_1 \times (1 - V_2) = P_{\text{th}} \times (1 - \eta) \tag{5}$$

If this process is repeated for each of the feature costs associated with the items in Table 9, a cost feature scaling model for the overnight capital cost can be built, as shown in Fig. 10. As can be seen from Fig. 10, a given scaling variable would not necessarily affect every cost feature.

4.4.3.5. Cost multiplication factors

As mentioned above (see Fig. 9), the third necessary step in building a screening method is to define the cost multiplication factors $K_{i,j}$. These factors are used to determine the new cost of any item *i,j* affected directly by a given design change d_k, as a product of the initial cost and the $K_{i,j}$ factor itself.

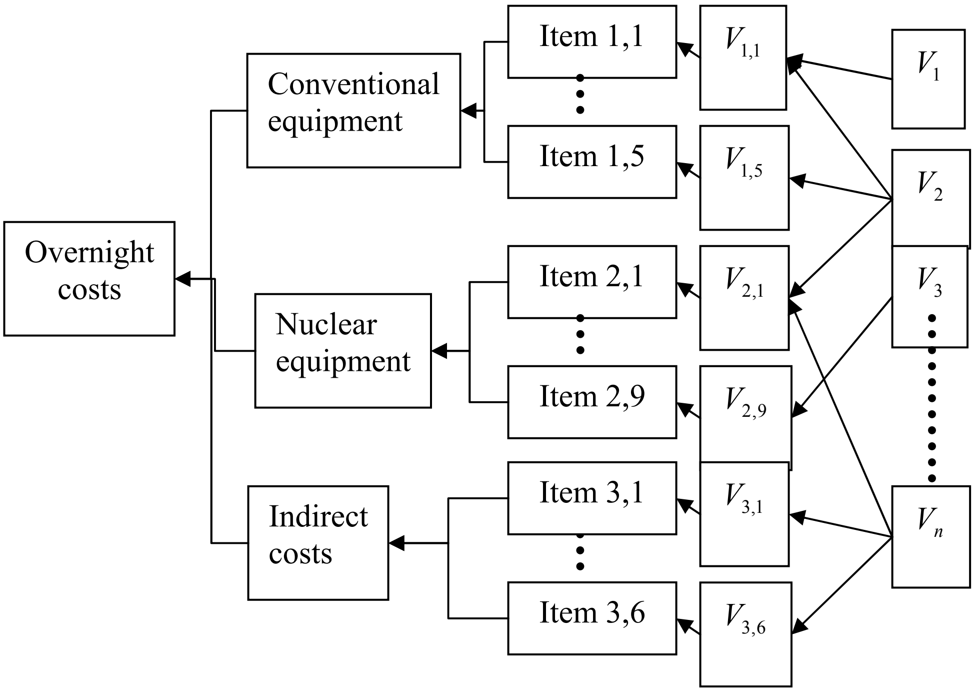

FIG. 10. Schematic flowsheet for the overnight cost calculation with n variables, the initial base costs and the scaling coefficient as inputs.

Using such factors, the new overnight cost directly associated with design change d_k would be:

$$\mathrm{CO}_{\mathrm{ON}} = \sum_{i=1}^{3}\sum_{j=1}^{N_i} I_{i,j} \times K_{i,j}^{d_k} \tag{6}$$

In this equation, the K factors account only for the directly envisioned cost effects resulting from changes in component size, redundancy, etc., which are direct consequences of the design change d_k. The K factors do not account for cost feedbacks resulting from component interdependence and will, therefore, depart from unity only for those components that are directly affected by the design change d_k. As it is often difficult to determine a precise value of the K factor, the value used could represent a guess or a number that could change within a given range.

4.4.3.6. Feedback effects and combination into a single model

When the K factors have been determined, the final step in the screening method is to relate the design change d_k to changes in the scaling variables, so that the cost feedback effects (neglected by the K factors) can be accounted for. This step is illustrated schematically in Fig. 9, which includes both the direct effect (K factors) and the feedback effects associated with a given design change d_k.

Previously, the feature cost scaling model was explained in the example of features associated with the overnight capital cost (Fig. 10). In reality, as shown in Fig. 8, several elements enter into the competitive target (or figure of merit) in addition to the overnight costs, many of which may also be affected by a given design change d_k. By calculating the effect of design changes on all of these cost components, the screening method allows alternatives in design simplification to be compared on the basis of a common competitive target.

4.4.3.7. Test application of the model

Annex II presents detailed results of the model application to comparative assessments of a competitive target (LUEC) for several reactor design concepts taken from Refs [3, 4, 6]. The model has shown good agreement with the design data on LUEC, not only for the cases of differently sized and designed reactors belonging to the same reactor line, e.g. water cooled reactors, but also for cases when design changes involved a transition from water coolant to gas coolant and from water coolant to sodium coolant.

4.4.3.8. Summary

The presented model for systematic assessment of reduced design complexity, based on a simple screening method, is a model that could be useful for design organizations of advanced SMRs to compare alternative design approaches to plant simplification from an economic perspective on the basis of a common competitive target, starting from early design stages when the design concept is not yet ‘frozen’ and the detailed design data are not finalized. In this, reference points could be selected from a variety of other reactor designs for which detailed design data are available. The model discriminates between the external parameters that remain beyond the control of a design organization, and the design and project parameters for which different values could be progressively included in screening to determine the conditions under which various design alternatives become competitive. The IAEA is neither in the position to endorse nor discourage the use of any models and alternative approaches.

4.4.4. Models to take into account uncertainties

As figures of merit, such as the LUEC, are being used to support decision making regarding energy strategy and the investments, it is important that a high degree of accuracy be provided in the calculation of these figures. However, such accuracy may prove elusive due to large uncertainties in the input variables. Indeed, costs of materials for power plants may vary with time, depending on market conditions. Prices for organic fuel also show a high degree of variation; they tend to rise periodically and then go down owing to financial crises, in an unpredictable timeframe. Interest rates (defining the cost of capital) may change substantially over time depending on the economic situation in a country. In addition to this, the utilities in countries planning to import nuclear technology, in most cases, have limited access to much of the cost data required for a detailed independent calculation of, for example, LUEC.

To cope with the factors mentioned above, calculations of the figures of merit could be performed using the Monte Carlo method added to simulate the uncertainties. The goal of adding the uncertainties is to provide more informative results compared to those obtained with best estimate calculations alone [18].

It should be noted that business planning taking into account uncertainties (based on stochastic models) is currently quite common in areas other than nuclear energy. The study highlighted here gives an example of how a stochastic method could be applied to treat the uncertainties in the calculations of a comparative figure of merit, involving a nuclear option. Further details of this particular study are available in Annex III.

To calculate a figure of merit with the uncertainties simulated using the Monte Carlo method, the following generic steps are necessary:

(a) Estimate the uncertainty ranges in each of the input variables.
(b) Determine the PDFs for the input variables within their respective uncertainty ranges.
(c) Specify correlation factors for each input variable with respect to each of the others to define the interdependence among the input variables. For instance, a correlation factor of one implies a high degree of interdependence, whereas a value of zero implies complete independence.
(d) Generate random values for each of the input variables within their respective uncertainty ranges on the basis of their PDF. A Monte Carlo random number generator is used for this purpose.
(e) For each complete set of randomly generated input variables (component values), calculate a random output value (composite value) on the basis of the figure of merit equation, and repeat steps (d) and (e) until a PDF of the output variable is generated.

In the study highlighted here, the previously mentioned five step process was applied in a comparative study of gas, coal and nuclear power options in Croatia. For a best estimate figure of merit calculation, the relationship for a discounted cost of electricity generation (called the levelized busbar cost) in the period of loan repayment and in the following period until the end of the plant lifetime was used. This relationship is given as Eq. (III–1) in Annex III, together with an explanation of the meaning of each of its constituents.

The model allows the user to select between three distribution types for the PDFs of the random input variables: uniform distribution, triangular distribution and five point distribution. Consistent with these distribution types and the recommendations provided in Ref. [20], the input data used for calculations in the Croatian study are reproduced in Table 11.

TABLE 11. ESTIMATED PLANT COST DATA (CROATIAN STUDY)

Plant type	Nuclear	Coal	Combined cycle gas
Overnight specific investment cost — c_i ($/kW)			
Distribution	Triangular	Triangular	Triangular
End values	1900 2000 2100	1400 1500 1600	500 600 700
Constant operation and maintenance cost (no fuel) — c_{com} ($/kW)			
Distribution	Flat	Flat	Flat
End values	100 120	30 40	10 20
Variable operation and maintenance cost — c_{vom} (¢/kW·h)			
Distribution	Flat	Flat	Flat
End values	0.15 0.25	0.30 0.40	0.15 0.25
Fuel cost ($/GJ)			
Distribution	Five point	Five point	Five point
End values	0.45 0.475 0.5 0.525 0.55	1.8 1.9 2.0 2.1 2.2	4.0 4.25 4.5 4.75 5.0
Plant efficiency			
Distribution	Flat	Flat	Flat
End values	0.32 0.34	0.38 0.42	0.54 0.62
Load factor			
Distribution	Triangular	Triangular	Triangular
End values	0.6 0.7 0.8	0.5 0.6 0.7	0.4 0.5 0.6
Years of loan repayment			
Distribution	Flat	Flat	Flat
End values	15 20	15 20	12 15
Years of plant lifetime	40	35	30
Discount rate (%)			
Distribution	Flat	Flat	Flat
End values	5 8	5 8	5 8

TABLE 11. ESTIMATED PLANT COST DATA (CROATIAN STUDY) (cont.)

Plant type	Nuclear		Coal		Combined cycle gas	
Average interest rate for loan repayment (%)						
Distribution	Flat		Flat		Flat	
End values	5.5	7.5	5.5	7.5	5.5	7.5
Average annual rate of fuel price increase (%)						
Distribution	Flat		Flat		Flat	
End values	0.8	1	1	2	2	5

For each energy source listed in Table 11, the selected figure of merit was calculated 2000 times, with the results spread out over 50 cost intervals to obtain the PDF of the output value with a high degree of resolution. The results of these calculations are shown in Fig. 11. As can be seen from this figure, nuclear power turns out to be cheaper than gas and coal, on average. Yet, because the PDFs overlap, there is an element of ambiguity in this conclusion (especially for nuclear versus coal), which results from the real world complexity as reflected in the random input variables.

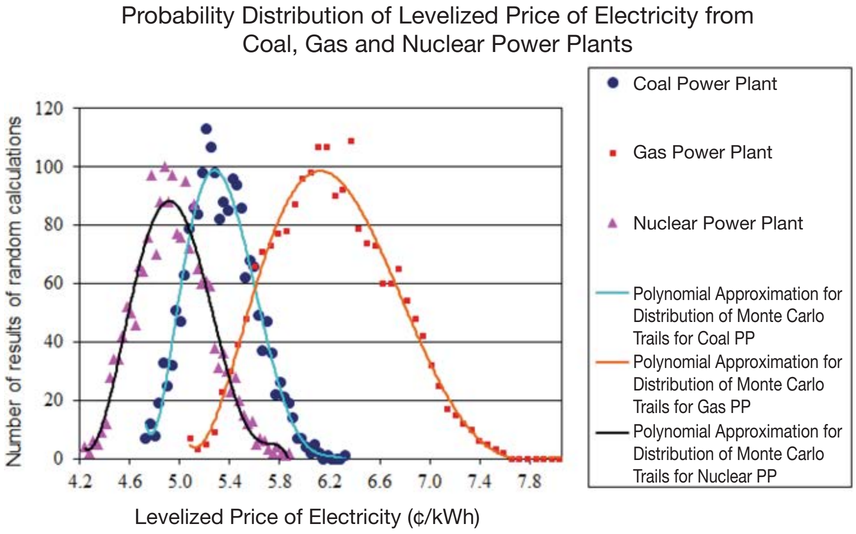

FIG. 11. Distribution of levelized unit electricity cost for coal, gas and nuclear power plants (case study of Croatia).

It is important to note that strict rules for the assignment of PDFs did not exist, and the databases supporting the definition of uncertainty ranges and parameter distributions for a variety of input parameters affecting the competitiveness of a nuclear option were sparse at the time when this report was prepared. Borrowing from historical data and further effort on compilation of the relevant databases might, therefore, be recommended to foster broader application of the uncertainty analyses in comparative economic assessments of a nuclear option.

4.4.4.1. Short conclusion

Whenever comparative assessments of an economic figure of merit are performed for competing energy options, taking into account the uncertainties of the input parameters may help better capture the real world complexity and ambiguity related to ever changing prices of commodities and energy carriers, and varying interest rates. The uncertainties were evaluated by first defining an uncertainty range and assigning PDFs to each of the input variables. Afterwards, random values (of each of the input variables) were generated for the subsequent multiple calculations of a selected figure of merit, by using the Monte Carlo random number generator. The limitation of the model is the absence of strict rules for the assignment of PDFs and a deficiency of the databases that could support determination of the uncertainty ranges and parameter distributions within these ranges. The intention of the IAEA is to provide a balanced overview of models including uncertainties as an available option for Member States interested in minimizing the influence of various factors already mentioned in the description.

4.4.5. Scenario analysis models

Scenario analysis models are typically associated with simulations of large expanding energy systems over a long period of time. At the IAEA, the INPRO project examines sustainability issues of a long term and large scale global and regional nuclear energy expansion [6, 7]. The overall scope of energy system assessment and modelling, as addressed by INPRO, is schematically shown in Fig. 12.

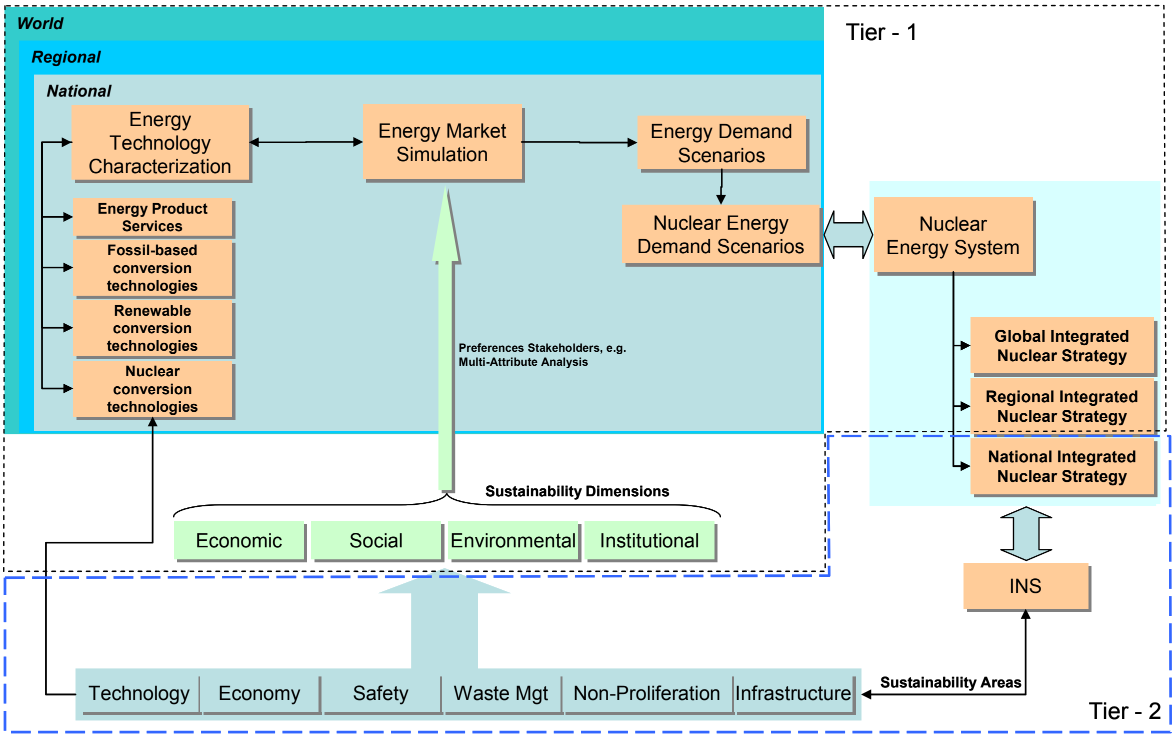

FIG. 12. Energy expansion issues addressed by the International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO) [4]. INS: innovative nuclear energy system.

While issues associated with a sustainable energy system expansion are diverse (as can be seen from Fig. 12), it is dynamic mass flow simulation that is at the core of most of the scenario analysis models. Material flow analysis (MFA) aims at analysing the mass flows of all fissile and fertile materials and other materials within a nuclear enterprise. The time evolution of a developing nuclear energy enterprise can be modelled as a dynamic system evolving from the current initial conditions and subject to the changing constraints of resource availability, reactor technology and fuel cycle lag time. MFA computer models are used to intercompare nuclear deployment strategies by providing a full analysis of the mass flows resulting from candidate strategies. They allow planners to assess the impact of choosing between alternative options in terms of time dependent resource and waste mass flows.

Once the MFA is accomplished, it provides a basis for possible ancillary analyses, such as:

- Life cycle inventory/life cycle assessment which address the environmental stresses that nuclear deployments might induce and their impacts on humans and the biosphere;

- — Analysis of the front end fuel cycle infrastructure requirements that addresses the time dependent requirements in front end fuel cycle services, such as enrichment works;
- — Waste management analysis that focuses on the amounts, types and impacts of radioactive waste being produced by the nuclear enterprise considering, for instance, partitioning and transmutation related fuel cycle options, and defining the time dependent requirements in fuel storage, disposal and reprocessing capacities;
- — Potentially, proliferation resistance analysis, once quantitative consensus approaches to the assessment of proliferation resistance features and measures become established;
- — Economic analysis that addresses the economic aspects of deployment of a large number of plants and associated nuclear infrastructure, including front end and back end fuel cycle facilities.

Numerous dynamic scenario computer codes based on MFA have been developed over the past decades. Table 12, taken from Ref. [5], gives an overview of the functionalities and capabilities offered by these codes, and the last rows indicate their availability.[13] As the goals of a typical scenario analysis are multiple, the economic/financing models used are often simplified if present at all (see Table 12). In addition to this, the uncertainties typically involved in longer term predictions may make the advantages of a detailed economic/financing model obsolete.

TABLE 12. CLASSIFICATION OF MFA MODELS AND TOOLS [5]

Code	COSI	DANESS	DESAE	DYMOND	NFCSim	ORION	OSIRIS	PROGNOSIS	SuperStar	VISTA
Equilibrium analysis										
— Single reactor	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
— Reactor park	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Dynamic analysis										
— Regional reactor park	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
— Multiregional reactor park	✓	✓	✓		✓	✓	✓			✓
Mass flow analysis										
Natural U–Th use	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Front end capacity needs and use	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Reactor core loading	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Back end capacity needs and use	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Separated material inventories	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Disposal needs	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Related functionalities										
Isotopic composition	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

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[13] Reference [17] provides more details about these codes.

TABLE 12. CLASSIFICATION OF MFA MODELS AND TOOLS [5] (cont.)

Code	COSI	DANESS	DESAE	DYMOND	NFCSim	ORION	OSIRIS	PROGNOSIS	SuperStar	VISTA
Decay heat	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Reactor core management	✓	✓	✓	✓	✓	✓	✓	✓		
Economics										
Levelized generation cost	✓	✓	✓			✓	✓	✓		
Investment needs		✓	✓			✓		✓		
Cash flow analysis		✓								
Environmental										
Life cycle inventory										
Life cycle analysis										
Waste management										
Repository impact	✓	✓		✓					✓	
Sociopolitical										
Proliferation risk					✓					
Availability										
Free			✓							✓
Licence agreement	✓	✓		✓	✓			✓	✓	
Commercial						✓	✓			

Note: The ✓ symbol indicates that the functionality or capability is available in the code; MFA: material flow analysis.

4.4.5.1. Short conclusion

Scenario analysis models are typically intended to perform simulations of large expanding energy systems over a long period of time. The main kernel of these models is dynamic simulation of material flows. Once a dynamic MFA is accomplished, this provides a basis for many ancillary analyses, possibly including a simulation of the economics and investments. As the goals of a typical MFA are multiple, the economic/financing models used are often simplified, if present at all. Incorporation of more detailed economic models is, however, not precluded. The strength is the dynamic nature of the MFA outputs and coverage of a complete energy system. All in all, in this report, the strengths and the weaknesses of these models are presented in an unbiased way, and it is up to Member States to choose them over other models.

4.5. CONSOLIDATED APPROACH TO THE APPLICATION OF MODELS RELEVANT TO THE ASSESSMENT OF SMR COMPETITIVENESS

4.5.1. Introduction

Section 4 has presented a variety of models available for the assessment of separate factors that may affect competitiveness of SMR based projects versus those based on larger reactors. An overview of a consolidated approach to the application of such assessment models for the purpose of guiding design development of the advanced SMRs and identification of the deployment approaches preferable for targeted applications of such reactors, starting from an early design stage, is given here. An important point is that models involved in the economic competitiveness assessment may need to be simple enough to allow treatment of preliminary economic data available for the reactors that are still in the early stages of design. However, as far as guidance to be provided, a consolidated application of the models needs to be sufficiently comprehensive.

A consolidated approach to SMR economic competitiveness assessment will be illustrated in an example of the development of the integrated model for economic competitiveness analysis of SMRs (INCAS) ongoing in the Politecnico di Milano (Italy), with support from the Westinghouse Electric Company and the Georgia Institute of Technology (USA). This model addresses investment analysis for given scenarios of nuclear power plant deployment through a holistic approach, considering quantitative and qualitative performance indicators. The former represents cost effectiveness and profitability performance; the latter accounts for aspects not fully quantifiable or not monetary that may affect the investment success. INCAS architecture is modular, thus allowing interface with any new model or method, as they become available, able to bring deeper detail and reliability to the current simulation and modelling capabilities of INCAS. INCAS focuses on comparative assessment of deployment scenarios with SMRs and LRs, and does not provide for comparison with non-nuclear options. More details about the INCAS code can be found in Annex VI.

4.5.2. Overall framework of the integrated model

Figure 13 illustrates the overall structure of INCAS. The investment model, shown on the left hand side of Fig. 13, is based on a DCF model, and is designed to calculate the main economic and financial indices, such as LUEC, net present value (NPV), internal rate of return (IRR) and payback time (PBT), taking into account time distributed input parameters, which is important for the scenarios with a staggered build of nuclear power plants when the effects of learning, multiple unit co-siting and construction schedule need to be taken into account. As compared to levelized economic models, the DCF model provides a full set of information on the capital structure of the investor that is informative of the financial sustainability of the investment effort. Time series effects, such as cash transfer from one unit to another, may be accounted for by the INCAS DCF simulation model: the model gives the user the option to indicate if and how much of the cash flow generated by early deployed units can be invested in the construction of later ones, thus reducing the upfront investment requirements. Time series values related to debt stock evolution and the debt coverage ratio are made available to the investment decision maker by the model. Such information is related to the concept of financial risk. The financial risk concept is used in the foreground by INCAS, and together with investment profitability, it represents a key performance indicator. In order to estimate a comprehensive picture of the investment risk, the investment model provides a stochastic approach to incorporate the scenario input uncertainty. Appropriate PDFs are assigned to input parameters and elaborated using a Monte Carlo method to generate random values of each of the input variables. The output uncertainty and related variance analysis provide useful information of the investment project robustness to changed or adverse scenario conditions.

The model for the so-called ‘external’ (or additional) factors shown on the right hand side of Fig. 13 attempts to consider some social and market related factors, such as human resource availability, potential of local industry involvement, security of energy supply, and others that could be subjective and non-quantifiable, but are likely to produce a certain impact on decision making regarding different nuclear options. An analytical hierarchy process (AHP) is then suggested as a method to merge together the results of the financial assessment and stakeholder judgements on the external factors to make a final judgement on the attractiveness of an SMR based nuclear option compared to other nuclear options.

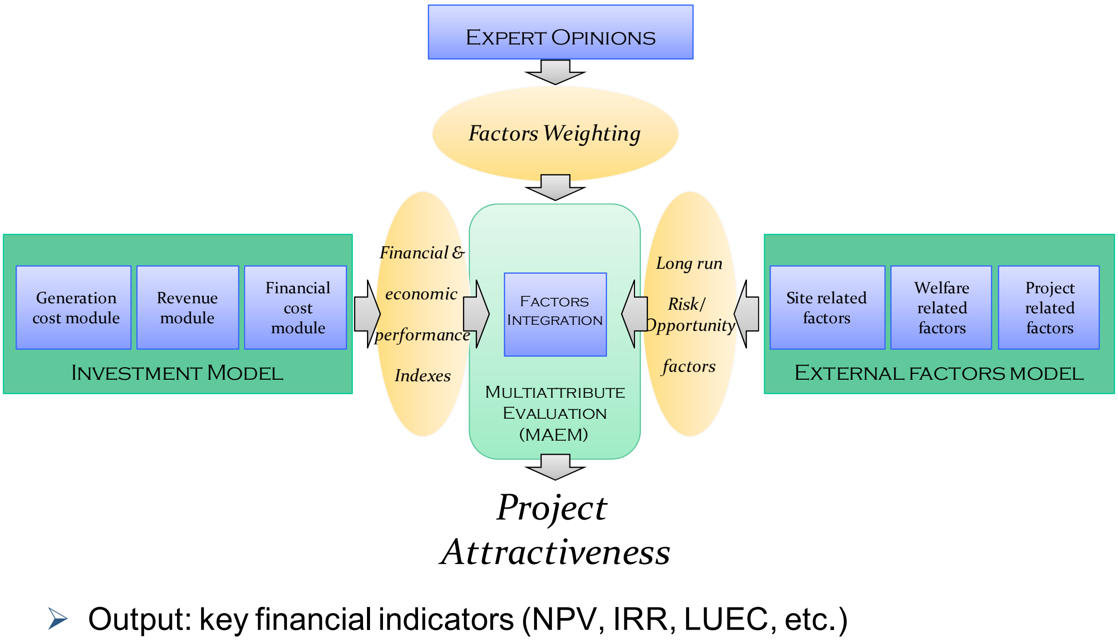

FIG. 13. Schematic diagram of the integrated model for competitiveness analysis of small and medium sized reactors (INCAS; Politecnico di Milano, Italy). IRR: internal rate of return; LUEC: levelized unit electricity cost; MAEM: multiattribute evaluation; NPV: net present value.

To be applicable to a comparative investment risk assessment of the deployment scenarios with SMRs versus larger reactors, the integrated model shown in Fig. 13 needs to include the separate models taking into account all economic and external factors that affect such an assessment. For example, the models described in Section 4.4 could be part of the investment model.

The following sections summarize the generic provisions of the developers of INCAS for separate components of this integrated model. A more detailed discussion of these provisions in provided in Annex VI.

4.5.3. The generation cost model

The generation cost model is identical to the LUEC model described in Section 4.4.1 [16, 19]. For INCAS, however, it is important to identify how the generation cost model can be used to treat the factors important to a comparative assessment between SMRs and larger reactors. Assuming that the total cost (LUEC) can be split into the cost of investment and the cost of O&M ($\mathrm{TC} = \mathrm{TC}^{\mathrm{I}} + \mathrm{TC}^{\mathrm{OM}}$, where TC is total cost), the cost elasticity with respect to size or scale S can be defined for each of these cost components. For the investment cost, the elasticity is:

$$n^{\mathrm{I}} = \frac{\partial \mathrm{TC}^{\mathrm{I}} / \mathrm{TC}^{\mathrm{I}}}{\partial S / S} \tag{7}$$

And for the O&M cost, the elasticity is:

$$n^{\mathrm{OM}} = \frac{\partial \mathrm{TC}^{\mathrm{OM}} / \mathrm{TC}^{\mathrm{OM}}}{\partial S / S} \tag{8}$$

As data from several sources show that both parameters are positive numbers less than one (see Annex VI for details), it follows that other things being equal, LRs would have advantages with respect to size or scale.

On the other hand, with respect to learning economies and co-siting, the situation may be reversed. To illustrate this, let N^S, N^U and N^W represent the number of identical units on a particular site, the number of identical units owned by a given utility at several sites, and the number of identical units produced by a given supplier worldwide, respectively. Based upon these definitions, the elasticity of the total cost of investment with respect to the number of units is given by:

$$l^i = \frac{\partial \mathrm{TC}^{\mathrm{I}}/\mathrm{TC}^{\mathrm{I}}}{\partial N^i/N^i} \text{ for } N^{\mathrm{I}} > 1 \tag{9}$$

Here, the letter *l* has been used to signify a learning elasticity and the superscript *i* is used as a general place holder for *S*, *U* and *W*, respectively. As has been shown in Section 4.5.2, the unit cost for standardized serial production drops rapidly for the first few units and then approaches an asymptotic limit. Thus, l^i is a negative number that approaches zero asymptotically. Moreover, when multiple units are built on the same site, the cost drops most rapidly because the learning curves of the supplier, the utility and the contractor all come into play. In this way:

$$l^S \leq l^U \leq l^W \leq 0 \tag{10}$$

The discussion above shows how the generation cost model can be used to capture the effects of both scale and learning economies.

The INCAS model identifies and quantifies a learning accumulation process on the same site, and a learning transfer from one site to another. Three cost components are identified (learning on factory equipment, labour and materials), each with a different learning elasticity, defined as a cost saving at each doubling of the power installed on the same site. Learning on equipment refers to the savings achieved by mini-serial factory fabrication; as it is developed at factory level, this learning component is site independent. On the contrary, learning on material handling is considered as an expertise strictly developed on-site and not exportable from one site to another. Labour expertise has different on-site and extra-site elasticity. The total learning factor is calculated using:

$$K = K_{\mathrm{eq}}\left(N_{\mathrm{world}} + N_{\mathrm{site}}\right)^{-\alpha} + K_{\mathrm{lab}} + \left(N_{\mathrm{world}} + 1\right)^{-\beta_2}\left(N_{\mathrm{site}}\right)^{-\beta_1} + K_{\mathrm{mat}}\left(N_{\mathrm{site}}\right)^{-\gamma} \tag{11}$$

where

α	is the learning in factory equipment;
β_1	is the labour learning on-site;
β_2	is the labour learning in the world;
γ	is the learning on material handling and use;
K_{eq}, K_{lab} and K_{mat}	are the percentage costs of equipment, labour and material in the total cost of a first of a kind unit, respectively;

and N_{world} and N_{site} are the number of nuclear power plants of the same type, already built worldwide and on the same site, respectively.

Figure 14 plots the percentage of learning factor as a function of number of reactor units on the same site, for different values of identical nuclear power plant units.

Other factors in addition to learning contribute to compensating SMRs for the loss of economy of scale:

- — Modularization;
- — Co-siting economies;
- — Design based factors.

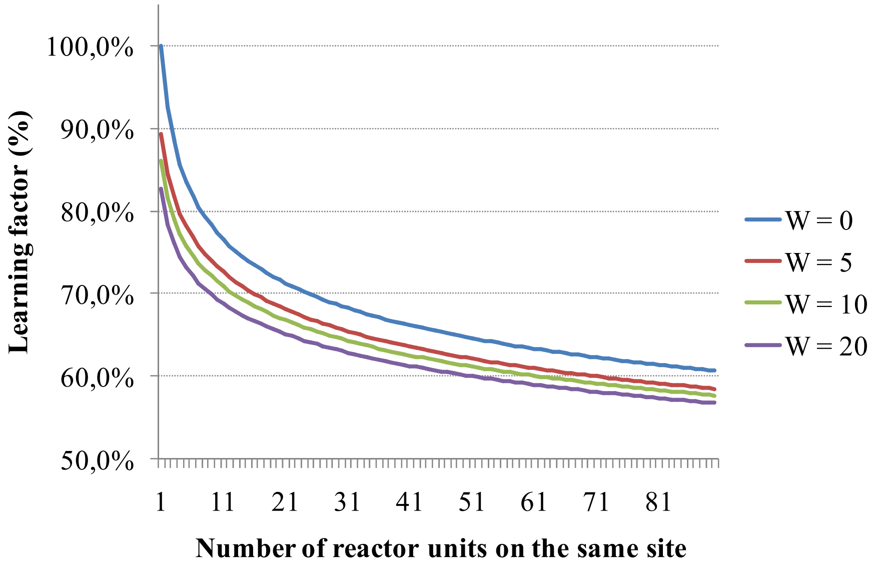

FIG. 14. Learning factors.

Modularization deals with plant engineering suitable for factory fabrication and the shift from stick built to shop built approaches. Plant layout is suitable for parallel and independent module installation. Modularization is possible for large monolithic reactor plants (ABWR, ESBWR, AP1000), but the smaller size of SMR components and systems allow more emphasis on modularization. Accordingly, INCAS assumes a higher construction cost reduction with a lower plant size. Figure 15 explains that modularization increases from 60 to 100% as the capacity of the reactor increases from about 50 to 1000 MW(e).

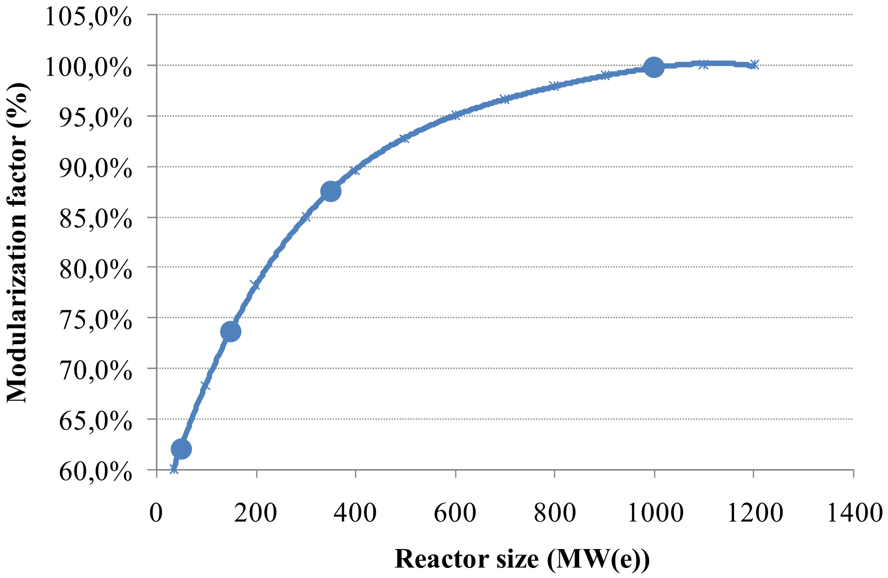

FIG. 15. Modularization factors.

Co-siting economies refer to fixed, site related costs shared among multiple units built on the same site. Figure 16 illustrates co-siting economy factors. The figure explains that the loss of economy of scale fully applies to the first SMR of a series due to full endorsement of fixed costs. Nevertheless, when more units are built on the same site, a corrective factor has to be applied to reduce the construction cost of each unit, to take into account the fixed costs shared among all nuclear power plant units. Co-siting economies also apply to large plants when they are built in a series on the same site. Nevertheless, SMRs are more eligible to be built in series on the same site, given the total power output constraints on a single site (due to cooling, grid capability, etc.) and, therefore, co-siting economies represent a relevant cost saving factor for multiple SMRs.

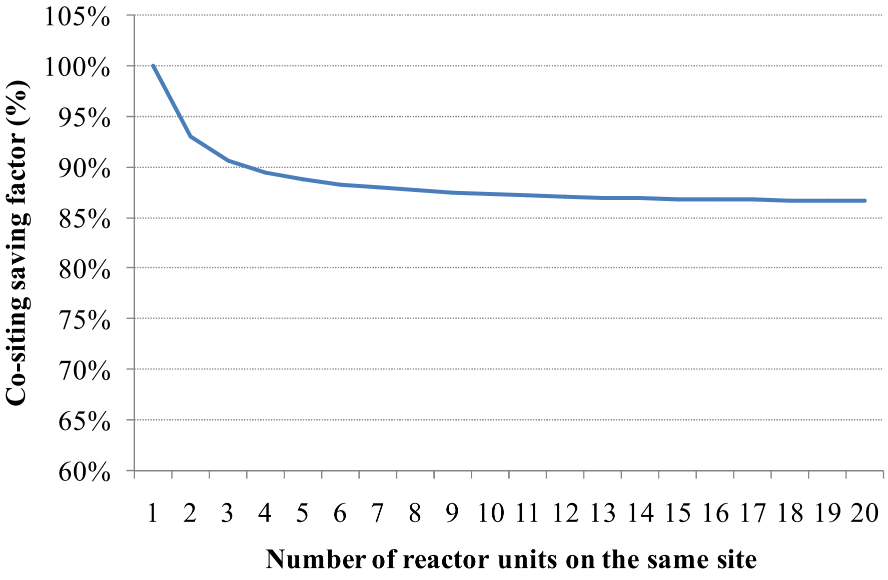

FIG. 16. Co-siting economy factors.

In addition to the above mentioned factors, design related enhancements and simplification are considered; better plant layout and enhanced passive safety are facilitated by lower plant output size and translate into additional cost savings. Primary loop integration and elimination of a number of active components account for lower costs due to lower amounts of material/equipment required and due to higher plant layout simplicity.

Design saving factors may represent the most controversial parameter, very specific to a given SMR concept design. In a top-down approach, it is provided by 'expert elicitation', and may be biased by subjective evaluation. A more reliable estimation of the design factor may be obtained by a bottom-up approach that accounts for specific and detailed design references.

The above mentioned factors (economy of scale, learning, co-siting economies, modularization and design savings) concur to a top-down estimation of the overnight construction costs of each successive SMR, assuming that the cost of the *N*th unit of a series is not equal to the others.

4.5.4. The revenue model

The purpose of the revenue model is to forecast electricity demand and market prices in order to estimate future annual cash inflows. Some of the elements that could enter into such a model include:

- Electric capacity already installed;
- Degree of competitiveness among the suppliers on the market;
- Mix of energy technologies for electricity production;
- Electrical grid structure and capability;
- Space–time trends of the demand for electricity;
- Adopted competitive strategy for new power plants.

The output of the revenue model is *total revenues* at the plant level over the economic plant lifetime, i.e. estimates of the total inward cash flows. The revenue *R* [€] is a function of the country or local level electricity consumption Q [MW(e)·h], the market price p [€/MW(e)·h] or the market structure drivers, **MS**[14], the plant size S [MW(e)], the specific reactor technology T (e.g. whether the reactor is an LR or an SMR), and a set **Y** of other variables:

$$R = R(Q, p \text{ or } \mathbf{MS}, S, T, \mathbf{Y}) \tag{12}$$

The **Y** inputs include the load factors, the national electrical grid and the front end investments.

It is not the purpose of the INCAS code to provide an electricity market simulation model, which necessarily has to be country dependent, in order to acknowledge the specific market structure and players (i.e. market pools, etc.).

As an open model, INCAS is able to be interfaced with appropriate market models and use their outputs (i.e. long term forecasted electricity price and power output demand) as an input for its elaboration.

4.5.5. The financial cost model

The purpose of the financial model is to evaluate the cost of investment capital. Here, the weighted average cost of capital (WACC) can be calculated by:

$$\text{WACC} = K_{\text{e}} \frac{E}{D+E} + K_{\text{d}}(1-t)\frac{D}{D+E} \tag{13}$$

where the necessary inputs are:

- Equity amount E invested in the project;
- Ratio of debt to equity D:E for the company, enterprise or organization, which is called the financial gearing;
- Rate of return required by shareholders for the equity K_{e}, which is the cost of equity;
- Interest rate required by debt holders K_{d};
- Tax rate t.

As nuclear power plant projects with smaller reactors are generically more scalable[15] and reversible, they may allow for better investment timing and smaller capital outlays, under certain scenarios that may result in lower risk, lower interest rates and lower D:E ratios. Thus, the WACC for SMRs may be lower than the WACC for LRs. The cost of capital also depends on the investment model, either project financing or corporate financing; in the first case, the cost of capital should represent the project specific financial risk; in the second case, financial risk could be endorsed and mitigated by the general credit rating of the investor and granted by its overall cash inflow portfolio. Other things being equal, project financing is generally represented by a higher financing cost than corporate financing and, without particular guaranties or contractual agreement able to reduce the project risk, it may simply be unviable. Such consideration has to be included in the cost of capital assumptions.

INCAS represents the shareholders' perspective: lenders' investment is treated as 'debt' and cash flows are considered net of financial interest and debt principal repayment ('free cash flows'). Accordingly, net cash flow values are actualized at the cost of equity, in order to calculate the NPV to shareholders. LUEC is calculated as the electricity price that is able to balance positive and negative net cash flows, actualized at the cost of equity.

New developments regarding financing options for nuclear power plants could eventually be incorporated in the model, such as provisions for sharing of financing costs already included in the IAEA's FINPLAN tool (see Section 4.2.2).

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[14] The **MS** includes total installed capacity, reserve margin, supply mix, concentration indices and market shares, spot power exchange versus long term bilateral contracts, etc.

[15] With capacity and investments added in smaller increments.

4.5.6. The investment model

The investment model evaluates the investment as a whole based upon the costs, the revenues and the interest rates derived from the previous three models. This evaluation provides for the calculation of the following main indicators:

- NPV;
- IRR;
- PBT;
- Profitability index (PI);
- LUEC.

Traditionally, economic studies of nuclear power generation focused on the generation costs (LUEC) calculation, with the LUEC being rated as a suitable reference value for comparative assessment of technologies to support decision making regarding certain energy options.

In the competitive, free electricity markets, investment decisions are often made by private companies seeking to maximize return on investment, subject to acceptable levels of risk and regulatory constraints. In such conditions, it may also happen that industrial projects, even if proven to be cost effective through LUEC analyses, may not be undertaken unless the estimated financial return is high enough to secure the market risks faced by private investors. For this reason, more recent studies and modelling efforts approach the economic attractiveness of an investment, not only from the generation cost point of view, but from a broader perspective, estimating PIs and other financial indicators, such as the NPV and the IRR (see Section 4.5.2 and Ref. [6]).

4.5.7. The external factors model

The overall evaluation of an investment may be affected not only by the quantitative parameters directly related to the investment model, but also by external, not always easily quantifiable factors. The external factors may be related to the:

- Degree of possible localization of an energy project;
- Benefits for local industry;
- Factors related to land use;
- Environmental laws (e.g. carbon tax and local emission constraints);
- Security of the energy supply;
- Strategic security of the fuel supply;
- Strength of the long term governmental commitment to nuclear power in a country.

Some of these factors may relate equally to nuclear power plants of any kind, while others are likely to be dependent on nuclear power plant size, type, construction period, overall number of targeted nuclear power plants, and the adopted deployment strategy. Moreover, quantification of some of these factors is likely to be based mostly on judgements of the involved stakeholders.

As a quantitative evaluation of such parameters is not straightforward, and as these parameters are not linked directly to the quantitative parameters coming from the investment model, finding a suitable method to merge the information becomes necessary. The developers of INCAS propose using the AHP to tackle the problem, as a method with potential to evaluate a global figure of merit for the different strategies and solutions under analysis.

4.5.8. The multiattribute evaluation model

The developers of INCAS assume that classical techniques for economic and financial evaluations, especially the DCF models, are, in some cases, not completely suitable in providing a thorough picture of the investment and its real value, as they do not take into account all of the positive features and disadvantages of a project. Nevertheless, they rate such techniques as obligatory because they operate on parameters and variables that are quantitatively expressed, with no possibility to elaborate intangible elements.

The multiattribute or multicriteria techniques (multiple attribute decision making) are then incorporated to address those situations when a choice between the number of alternative options is to be performed, given a set of attributes of a different kind, including those of not tangible nature or not easily measurable in monetary terms.

One of the better elaborated multiattribute techniques, the AHP, has been selected for the evaluation of the attractiveness of nuclear power plant projects in INCAS (Fig. 17). This method represents an explicit method to quantify the evaluation elements, even if they are of a non-tangible nature. The procedure organizes the estimation process in a hierarchical manner. This allows assignment of a weight to each different attribute/criterion by means of a systematic set of comparative evaluations among pairs of attributes/criteria. The decision is, thus, decomposed at sequential levels, where the first level represents the objective of the evaluation (e.g. project attractiveness), and the second and following levels include the attributes and subattributes with significant importance for the goal. Each attribute and subattribute can be decomposed up to the suitable level of detail. The last level belongs to the different alternatives under examination.

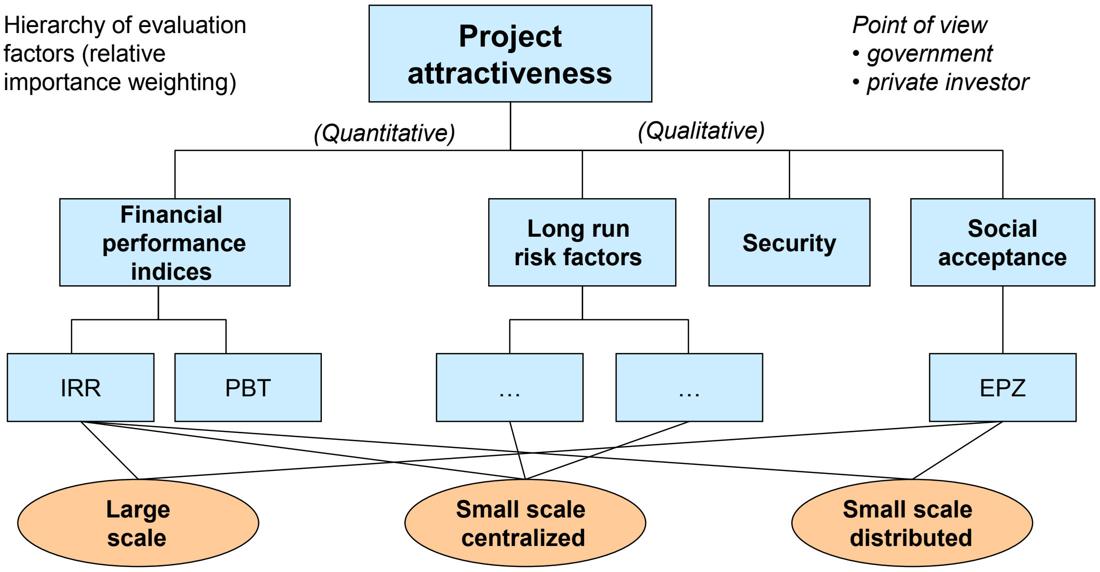

FIG. 17. Structure of the analytical hierarchy process (AHP) as used in the integrated model for competitiveness assessment of small and medium sized reactors (INCAS). EPZ: emergency planning zone; IRR: internal rate of return; PBT: payback time.

In comparison with the models that appear easier to read and apply, but which deal only with the analysis of homogeneous information sets, the AHP allows examination of the project alternatives characterized by highly heterogeneous evaluation elements. The AHP also allows analysis of the sensitivity of the final evaluations to project assumptions (see Annex VI for more details).

4.5.9. Model for taking into account uncertainties

The uncertainties in input parameters are taken into account using the method described in Section 4.4.4. The uncertainty analysis is implemented only within the investment risk model of INCAS, shown on the left hand side of Fig. 13.

4.5.10. Results of model application to a test case

The INCAS investment model was applied by its developers[16], on a trial basis, to a test case similar to that of Table 7, where four sequentially built SMRs are compared to one large reactor of the same overall capacity. The parameters of the test case used for the INCAS calculations are given in Table 13.

The data given in Table 13 are of a generic character and are not linked directly to any particular reactor design.

TABLE 13. ASSUMPTIONS FOR A MODEL EXAMPLE — TEST CASE FOR INCAS

Parameters	Values
SMR-4 to large reactor size ratio	1:4 (300 versus 1200 MW(e))
Equity/(equity + debt)	50%
Electricity price	€70/MW·h
Specific overnight construction cost of a large reactor	€3000/kW(e)
Cost of debt	8%
Cost of equity	15%
Capacity factor	95%
Design saving factor for an SMR	10%
Cost saving factor related to higher degree of modularization of an SMR	15%
Co-siting factor (fixed cost sharing)	SMR-2, SMR-3 and SMR-4 have 93, 91 and 89%, respectively, of SMR-1 unit costs
Learning effect in construction costs	
SMR-2	92.5% of SMR-1
SMR-3	88.4% of SMR-1
SMR-4	85.6% of SMR-1

Note: INCAS: integrated model for competitiveness assessment of small and medium sized reactors; SMR: small and medium sized reactor.

The construction schedules and the cash flows associated with the considered case are given in Figs 18 and 19. The sources of financing of the SMR based project corresponding to the case of Table 13 are shown in Figs 20 and 21. It can be seen that financing of the fourth sequential SMR is partly performed at the expense of profits gained after putting into operation the previous SMRs.

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[16] All of the data and results in Section 4.5.10 were obtained by the Politecnico di Milano (Italy) and presented at an IAEA technical meeting in June 2009.

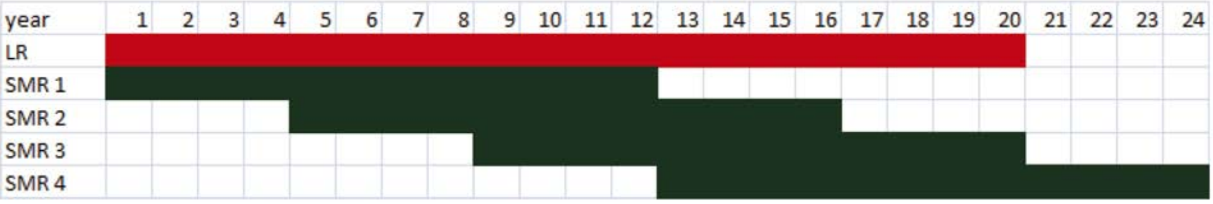

FIG. 18. *Construction schedule of large reactors (LRs) and small and medium sized reactors (SMRs): staggered build of four SMRs versus one LR of the same overall capacity (scenario I).*

FIG. 19. *Scenario II construction schedule for a small and medium sized reactor (SMR): more staggered build. LR: large reactor.*

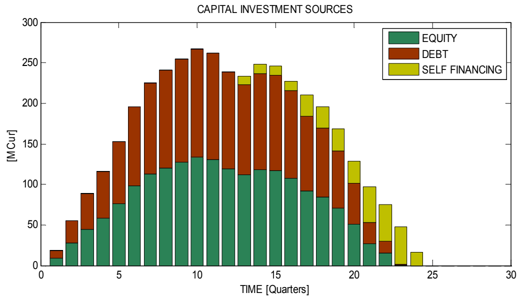

FIG. 20. *Source of small and medium sized reactor financing (scenario I).*

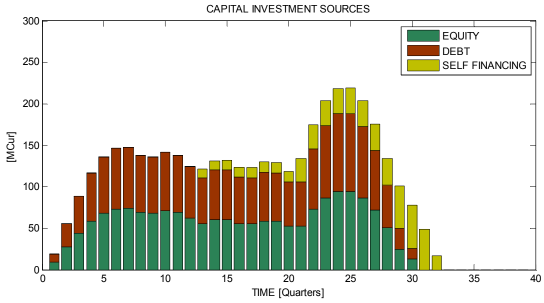

FIG. 21. *Source of small and medium sized reactor financing (scenario II).*

Figures 22 and 23 present the debt stock profiles for SMR and LR investment projects, respectively. Table 14 presents key financial indicators for the LR and SMR investment cases. It also includes a sensitivity analysis on electricity price value, assessing the effect of a decrease from €0.70/kW·h. to €0.60/kW·h.

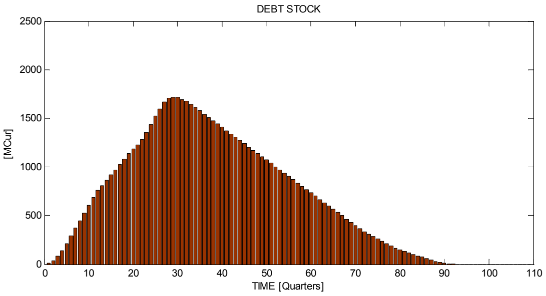

FIG. 22. *Debt stock profile of a small and medium sized reactor (scenario II).*

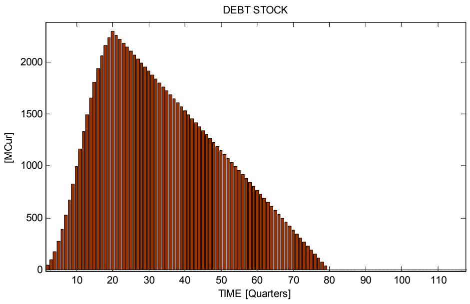

FIG. 23. *Debt stock profile of a large reactor.*

TABLE 14. NPV AND IRR VALUES CALCULATED FOR THE TEST CASE

	SMR project (scenario I)	LR project
Case of Fig. 20	LUEC = €69/MW·h NPV = –€26.5 million IRR = 15.3% PBT = 11.5 a	LUEC = €69/MW·h NPV = €42.1 million IRR = 15.4% PBT = 11.25 a
Case of Fig. 20, with electricity price decreased from €0.70/kW·h to €0.60/kW·h	NPV = –€333 million IRR = 13.0%	NPV = –€288 million IRR = 13.4%

Note: IRR: internal rate of return; LR: large reactor; LUEC: levelized unit electricity cost; NPV: net present value; PBT: payback time; SMR: small and medium sized reactor.

The data presented in Figs 20–23 indicate:

- A lower capital investment profile for the SMR and partial financing of later units at the expense of profits gained from putting into operation the previous ones;
- That the debt stock profile is also smoother, indicating less financial distress of the project;
- More staggered construction of SMRs increases self-financing (from €248 million to €465 million), reduces the upfront equity investment to €1700 million and may be affordable to a broader number of investors, if certain conditions hold.

Excessively staggered construction of SMRs delays full site power availability to the grid (Fig. 19) and shifts the cash inflows forward, decreasing both the NPV and IRR.

The presented data indicate that, in a considered test case, the SMR based project's cost effectiveness and profitability may be in line with an LR project, in the range of data and model uncertainties. Despite the broader construction schedule of SMRs, shorter PBTs of each SMR unit account for the overall project PBT in line with LRs (about 11 years). Capital remuneration requirements (cost of equity = 15%) are met in both SMR and LR cases.

INCAS is able to assess the impact of changed scenario conditions on investment performance. In this case, electricity price reduction accounts for 2% lower IRRs and a loss of about €330–360 million in project NPV. All results and conclusions presented here are of a generic and preliminary character. They are provided just to illustrate some of the assessments that could be carried out with an integrated model for the assessment of SMR competitiveness.

4.5.11. Summary

Here, an example of how separate models important for the assessment of investment attractiveness of SMR based projects could be applied in a consolidated way has been provided. A possible framework for the consolidation was illustrated in the example of INCAS being developed by the Politecnico di Milano in Italy. INCAS focuses on comparative assessment of deployment scenarios with SMRs and LRs, and does not provide for comparison with non-nuclear energy options. It is being developed for the purpose of guiding investment decision makers to identify the deployment approaches preferable for targeted applications of such reactors. The INCAS code is under review by IAEA experts on the subject. The IAEA is neither in a position to perform prescriptive code verification and validation nor to endorse the use of the model. Hence, it is left to the preference of the Member States to decide how to employ the model.

INCAS consists of the investment model and the external factors model. The investment model is being developed with a modular approach, with separate models concurring to calculate cash flow profiles and the main economic and financial indices, such as LUEC, NPV, IRR and PBT. The investment model is based on a DCF model that takes into account time distributed input parameters, which are important for the scenarios with staggered build of nuclear power plants when the effects of learning, unit timing, multiple units on the same site and construction schedule need to be taken into account. The investment model is currently under development to be able to deal with uncertainty analysis, based on assigning PDFs to input parameters and then using a Monte Carlo method to generate stochastic distribution of output parameters. The outputs then appear as values distributed within their calculated ranges of uncertainties.

The model for the so-called external (or additional) factors attempts to consider some social and market related factors, such as potential of local industry involvement, security of energy supply, and others that could be subjective and non-quantifiable, but which are likely to produce a certain impact on decision making regarding different nuclear options. The AHP is suggested as a method to merge together the results of the financial assessment and stakeholder judgements on external factors to make a final judgement on the attractiveness of an SMR based nuclear project. In addition to this, the resulting integrated model allows the performance of multiple sensitivity analyses with respect to any of the input parameters or assumptions.

INCAS is essentially able to define comparative investment risk and profitability for given scenarios of nuclear power plant deployment; it also keeps the door open to interfaces with any new model or method, as they become available. INCAS is currently still under development; therefore, its presentation in this report is just as an example of how the consolidated approach could possibly be achieved and the results that could be obtained with its application.

5. CONCLUSIONS

This report highlights the requirements for methods, approaches and tools for assessing the economic competitiveness of SMRs against different energy options and LRs, and presents the status of different methodologies currently under development. Certain concerns towards SMR technology are associated with technology provenness, verification of novel technology and implementation of verified technology. There are already countries to be considered, as points of reference with regard to SMR technology indicate that it is possible to counter the economies of scale through standardized and serial production. Argentina is an example of how countries with large territories and a scattered population can meet their energy requirements through turning to SMRs, while China’s nuclear power programme demonstrates how units of SMR range can be relevant in a country with high energy requirements. In India, SMR technology is an indispensable element of the country’s programme. Pakistan’s nuclear power programme includes only SMRs. In the Russian Federation, there is evidence that fabrication, installation and even repair costs drop due to serial production.

There are methods for assessing the economic performance of SMRs versus other energy options, and for comparing a number of SMRs to LRs with an overall equal capacity, that are presented in this report:

- MESSAGE and FINPLAN, developed by the IAEA, are tools that can be used in a combined manner for comparing SMRs with different energy options. MESSAGE identifies an optimal portfolio of energy supply facilities that should be built to meet the future energy demand, while FINPLAN evaluates the financial viability of the investment planned as determined by MESSAGE.
- LUEC is a figure of merit used for the assessment of economic aspects of power plants. It provides a benchmark for comparing competing reactor technologies with each other and with regards to alternative energy resources. G4-ECONS is the model for calculating LUEC that allows the evaluation of the relative costs of competing technologies and the optimization of technologies in the design state. Each section of the model computes a component of LUEC, which can be divided into four life cycle components.
- The PVCC model assesses factors affecting PVCC when several nuclear power plants are built in a sequence that includes economy of scale, multiple units, learning, construction schedule, unit timing and plant design, factors related to comparing the deployment of several SMRs versus fewer LRs.

Reducing design complexity is a factor for improving the competitiveness of SMRs. To achieve this design goal, a model for assessing the impact of plant simplification on specific overnight capital costs has been developed. The model for systematic assessment of design simplification is useful to designers of advanced SMRs for comparing alternative design approaches to plant simplification from an economic perspective. It is based on a screening method, and it discriminates between the external parameters for which different values could be included in screening to determine the conditions under which various design alternatives become competitive.

Design simplification models that take into account uncertainties are relevant for SMRs in order to facilitate coping with uncertain factors such as costs of materials for power plants, prices for organic fuel, interest rates and insufficient information about nuclear technology. The models that take into account uncertainties of the input parameters define the uncertainty ranges and assign the PDFs in order to better reflect the complexity and the ambiguity related to constantly changing prices, interest rates, etc.

Scenario analysis models examine the sustainability issues of a long term and large scale global and regional nuclear energy expansion. Dynamic mass flow simulation is at the core of most of the scenario analysis models. The scenario analysis models perform simulations of large expanding energy systems over a period of time through a dynamic MFA.

In addition to the above, a consolidated approach to the application of various models with regards to assessing SMR competitiveness is presented. INCAS provides the framework for bridging models. INCAS conducts a comparative assessment of deployment scenarios with SMRs and LRs exclusively, and consists of:

— The investment model, which incorporates separate models for calculating cash flow profiles and the main economic and financial indices and takes into account time distributed input parameters and uncertainty analysis.
— The external factors model, which deals with social and market related factors. These factors are not always easily quantifiable. Due to the fact that they are not linked to the quantitative parameters from the investment model, an AHP is used for merging the results.

In the end, multiattribute evaluation is incorporated for addressing situations when a choice between the number of alternative options is to be performed, given a set of various attributes, including those that do not have a tangible nature or are not easily measurable in monetary terms.

In this report, all methodologies are presented for enhancing the knowledge of the Member States on available approaches that have been developed or are under development for assessing aspects related to the economic competitiveness of SMRs versus other energy options or LRs. An overview of methodologies for comparing alternative design approaches, taking into account uncertainties and conducting scenario analyses is also provided. The Member States, according to their preferences and purposes, decide which methodology corresponds to their criteria.

In summary, SMRs may provide an attractive nuclear power option for developing countries with certain conditions, such as small electricity grids, remote areas and limited investment capability. The economy of multiple small modules and the associated risk reduction that can be achieved through design standardization, mass production, simplification, construction in series and more parameters need to be well defined, as they appear to be some of the important aspects that need to be considered. Offsetting the economy of scale through the economy of multiple units is a challenge for the design and deployment of SMRs. The evaluation models and tools that are presented in this report address key issues related to the competitiveness of SMRs versus other energy options and a series of SMRs versus LRs, and explore the impact of many special SMR characteristics on a range of considerations for potential stakeholders. The encouraging experience of countries such as Argentina, China, India, Pakistan, the Russian Federation and the USA, as well as the methods and models that have been developed, constitute an adequate basis that, in the future, can be further evolved and elaborated.

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Annex I

ARGENTINIAN EXPERIENCE AND PERSPECTIVES FOR SMALL AND MEDIUM SIZED REACTORS

National Atomic Energy Commission, Argentina

I–1. INTRODUCTION

The National Atomic Energy Commission (CNEA) was created on 31 May 1950. It was responsible for all nuclear activities in the country until 1994. In 1994, the regulatory body and the operational activities of nuclear power plants were separated. A utility named Nucleoeléctrica Argentina (NASA) was created.

The present missions of the CNEA are:

- To assist the national Government in nuclear policy;
- To provide research and development in nuclear areas, including nuclear power plants, research reactors and nuclear fuel cycles;
- To provide spent fuel and radioactive waste management, decommissioning of nuclear and radioactive installations, and environmental remediation;
- By itself or through related companies, to provide radioisotopes for medicine and industry, and provide services to nuclear power plants and conventional industries.

Development of human resources is yet another important objective of CNEA activities.

I–2. RISK BASED REGULATION

One of the main goals of nuclear regulations is to protect people from the hazards associated with nuclear energy production.

The Argentinian regulatory criterion related to the radiological risk associated with accidents at nuclear power plants is to keep the risk value below a reasonable level. The target is that an increase in the risk of death produced by radiological consequences of an accident at a nuclear power plant shall be lower than 10^{-6} per year for the critical group.

The radiological risk related to an accidental sequence depends on the probability of occurrence of such a sequence, on the associated effective dose and on the probability of death related to this effective dose.

The Argentinian regulation AR 3.1.3 [I–1] establishes criteria for the radiological risk associated with accidental conditions at nuclear power plants.

According to this regulation, a set of accidental sequences associated with potential public exposures shall be identified using an accepted methodology.

The annual probability of occurrence for each of the identified sequences shall be calculated using event trees and fault trees.

The failure analysis shall systematically cover all failure and accident sequences that can be foreseen, including combinations of failures and beyond design basis conditions.

Treatment of accidental sequences can be simplified by choosing those accidental sequences that are representative of certain groups of the sequences. In this case, a sequence with the worst radiological consequence shall be selected, and its annual probability of occurrence shall be calculated by adding the probabilities of all of the sequences in the corresponding group.

The analysis should assume that one train of the safety system is not operable to satisfy single failure criteria.

The analysis of failures and accidental sequences shall be based, as much as possible, on experimental data. If this is not possible, the evaluation methods shall be demonstrated by analytical studies.

In the evaluation of failure probabilities for systems, the failure probabilities assigned to the components shall be justified. If no justified values are available for a given component, the regulatory authority will indicate the value to be used.

The reliability values related to human actions shall be justified. The complexity of the task and other factors should be considered.

The radioactive dose of the critical group that results from the release and dispersion of radionuclides shall be calculated using accepted methods. Meteorological conditions and their probabilities shall be considered. No credit shall be taken for any countermeasure (i.e. evacuation).

No accidental sequence with radiological consequences for the public shall have an annual probability of occurrence that, plotted against the effective dose results, will result in a point located in the unacceptable region of the curve of Fig. I–1.

FIG. I–1. AR 3.1.3 criterion curve [I–1].

If the number *N* of accidental sequences is greater than ten, the allowed annual probability of Fig. I–1 is divided by *N*/10, in order to keep the overall risk below 10^{-6} per year.

I–3. OPERATING NUCLEAR POWER PLANTS

There are two operating nuclear power plants in Argentina, and they are both small and medium sized reactors (SMRs). These plants represent 5% of the Argentinian electrical market, but they generate 8% of the electrical energy. The NASA owns and operates both nuclear power plants.

Atucha 1 was the first nuclear power plant in Argentina. It began commercial service in 1974. It is based on a pressurized heavy water reactor (PHWR) supplied by Siemens (Germany). The net plant power is 335 MW(e).

The core of Atucha 1 was initially loaded with natural uranium, but it was eventually changed to slightly enriched uranium (SEU) [I–2]. In 1995, the first SEU fuel assembly was loaded, and in 2001, the whole core was loaded with SEU fuel assemblies. The SEU enrichment was 0.85%. This change increased the discharge burnup from 6000 to 11 000 MW·d/t U, producing cost savings. Embalse was the second nuclear power plant in Argentina. It began commercial service in 1984. It is based on a pressure tube heavy water reactor (HWR) supplied by Atomic Energy of Canada Limited (AECL). The net plant power is 600 MW(e).

I–4. FUEL CYCLE PLANTS

Since the beginning of its nuclear energy programme, Argentina has given much importance to fuel cycles associated with the installed nuclear power plant in order to guarantee energy production. This was an important point considered when, 40 years ago, heavy water cooled natural uranium fuelled reactors were chosen.

Argentina produced fuel assemblies for Atucha 1 and Embalse. A uranium conversion plant, a fabrication plant for special alloys and Zircaloy tubes, and a fuel assembly fabrication plant were constructed.

The domain of the uranium enrichment technology was also considered important, and a prototype gas diffusion enrichment plant was constructed.

A heavy water production plant was also constructed in order to guarantee the heavy water supply.

I–5. SPENT FUEL TEMPORARY STORAGE

For the Embalse plant, a temporary dry storage facility was locally designed and constructed by Argentinian companies, following the general concepts of dry concrete canister storage from AECL [I–3]. For Atucha 1, a second spent fuel pool was constructed, but a technical concept for temporary dry storage is currently under study.

I–6. ADVANCED FUEL ELEMENTS FOR HWRs

The two nuclear power plants in operation in Argentina have quite different designs, particularly for the fuel elements. The fuel originally designed for natural uranium had a discharge burnup of less than 8000 MW·d/t UO_2; this was increased to 11 000 MW·d/t UO_2 for Atucha 1, with the use of SEU. Both nuclear power plants use on-load refuelling, but they differ in the number and length of the refuelled elements. In Embalse, a Canada deuterium–uranium (CANDU) type reactor with a total of 12 fuel elements and a 6 m long channel was used, with 2 fuel elements refuelled at a time. On the contrary, the vertical channel of Atucha 1 has one single fuel bundle, 5.25 m long, in its active portion, and is hung by its upper part.

Within the CARA project [I–4, I–5], the CNEA is developing an advanced fuel element concept for HWRs, specially designed to fit the Argentinian fuel cycle requirements. The CARA fuel element can be used in reactors of both types, and would substantially improve the competitiveness of the nuclear option.

On the scale of small and medium sized developing countries, advanced designs that consider non-standard fuel rods and, therefore, increase the number of necessary different structural elements and welding steps, increase the overall fabrication cost. A new advanced fuel element to be developed should not only increase safety margins and fuel burnup, but decrease fabrication costs.

The CARA fuel is designed for conditions of operational nuclear power plants, mainly for the coolant flow and the hydraulic channel pressure drop; it is mechanically compatible with the refuelling machine of both vertical and horizontal channel reactors.

The CARA fuel has been designed to improve the major fuel performance of reactors of both types [I–6, I–7]. The CARA fuel element can reach higher fuel burnup using SEU, and has higher thermal-hydraulic safety margins, achieved via an increase in the number of fuel rods, together with a lower fuel pellet centre temperature and Zircaloy/(heavy metal) mass ratio. Moreover, it preserves the linear mass fuel density using a single fuel rod diameter, and minimizes the welding on claddings using three spacer grids per fuel bundle, similar to pressurized water reactor (PWR) technology, instead of the classical spacer pads welded onto the cladding.

The CARA fuel element has 52 single diameter collapsible fuel rods, each about 1 m in length, fastened by three spacer grids and two end plates (Fig. I–2). It uses SEU together with burnable poisons for extended burnup and negative void coefficients. For Atucha, it is necessary to join five CARA fuel elements using an additional coupling system external to the fuel bundles [I–8].

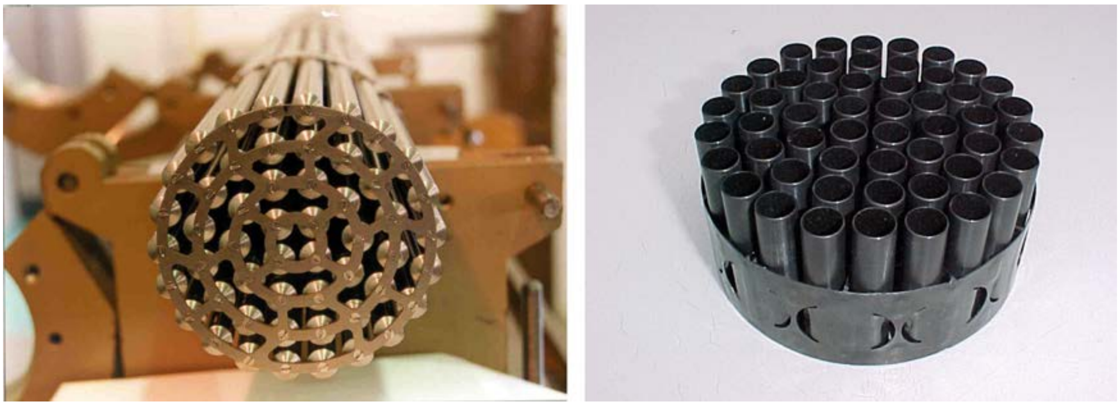

FIG. I–2. CARA prototype (left) and spacer grid prototype (right) [I–5, I–6].

I–7. NUCLEAR SECTOR COMPANIES

Over the years, many companies were created in order to deal with nuclear fuel related activities, heavy water production, nuclear reactor and facility design, research reactor construction, etc. The main nuclear sector companies are CONUAR, DIOXITEK, ENSI, FAESA and INVAP.

I–8. RESEARCH REACTORS

Argentina has developed important activities related to the design, construction and operation of research and isotope production reactors.

In Argentina, there are three research reactors, three critical facilities and radioisotope production plants.

However, the most interesting point is that Argentina has exported research reactors to Peru, Algeria, Egypt and Australia. The design and construction of these reactors give an important background for the construction of SMRs of local designs.

I–9. NUCLEAR PROGRAMME

The present Argentinian nuclear programme includes [I–9]:

- Completion and startup of the Atucha 2 nuclear power plant;
- Life extension of the Embalse nuclear power plant;
- Construction and startup of a fourth nuclear power plant;
- Construction and startup of a prototype Central Argentina de Elementos Modulares (CAREM) reactor;
- Resuming or enlarging D_2O production, uranium mining, fuel assembly production and low uranium enrichment activities.

I–10. ATUCHA 2 NUCLEAR POWER PLANT

Construction of Atucha 2 began in 1981. It employs a pressure vessel PHWR, and the reactor supplier was Siemens.

The net plant power is 692 MW(e) and the fuel is natural uranium.

The completion and startup are being resumed by NASA, with support from other Argentinian organizations. The startup commissioning began in 2013.

I–11. LIFE EXTENSION OF EMBALSE AND THE FOURTH NUCLEAR POWER PLANT

For Embalse nuclear power plant, a life extension of 25–30 years is planned. A nuclear cooperation agreement with AECL was signed [I–10]. Collaboration on the Embalse nuclear power plant life extension and a fourth nuclear power plant feasibility study were agreed with AECL.

I–12. CAREM

The Argentinian CAREM project [I–11] aims to develop, design and construct an advanced, simple and small nuclear power plant.

On 24 August 2006, the President of Argentina declared the construction and startup of the CAREM prototype a national interest of the Republic of Argentina (Presidential Resolution 1107/2006). The President gave orders to the CNEA and EBISA to perform the necessary activities for the construction and startup of the CAREM prototype (CAREM-25).

I–13. CAREM-25

CAREM-25 is an indirect cycle reactor with some distinctive features that substantially simplify the design and also contribute to a high safety level. Some of the high level design characteristics are:

- An integrated primary cooling system;
- Primary cooling by natural circulation;
- Self-pressurization;
- Safety systems relying on passive features.

I–13.1. The primary system

The CAREM reactor pressure vessel (RPV) contains the core, the steam generators, all of the primary coolant and the absorber rod drive mechanisms (Fig. I–3). The RPV diameter is about 3.2 m, and the overall RPV height is about 11 m.

The core of the prototype has 61 hexagonal cross-section fuel assemblies, each of about 1.4 m active length. Each fuel assembly contains 108 fuel rods, 18 guide thimbles and an instrumentation thimble (Fig. I–4). The components are typical of PWR fuel assemblies. The fuel is enriched UO_2. Core reactivity is controlled by the use of Gd_2O_3 as a burnable poison in specific fuel rods and movable absorbing elements belonging to the adjustment and control system. Chemical compounds are not used for reactivity control during normal operation. The fuel cycle can be tailored to customer requirements, with a reference design of 330 full power days and 50% core replacement.

Each absorbing element consists of a cluster of rods linked by a structural element (called a spider), so the whole cluster moves as a single unit. Absorber rods fit into the guide tubes. The absorbent material is the commonly used Ag–In–Cd alloy. Absorbing elements are used for reactivity control during normal operation (adjustment and control system), and to produce a sudden interruption of the nuclear chain reaction when required (first shutdown system (FSS)).

Twelve identical mini-helical vertical steam generators, of the once through type, are placed at equal distances from each other along the inner surface of the RPV (Fig. I–3). They are used to transfer heat from the primary to the secondary circuit, producing dry steam at 4.7 MPa, with 30°C of superheating.

The location of steam generators above the core produces natural circulation in the primary circuit. The secondary system circulates upwards within the tubes, while the primary system travels in a counter current flow. An external shell surrounding the outer coil layer and an adequate seal form the flow separation system. This guarantees that the entire steam of the primary system flows through the steam generators.

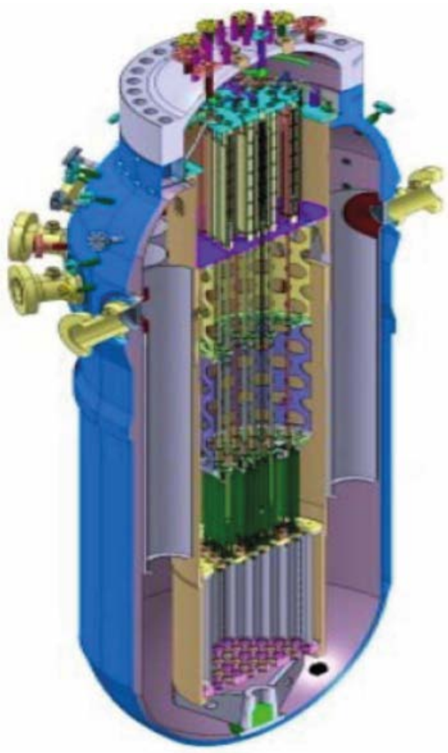

FIG. I–3. CAREM reactor pressure vessel [I–6].

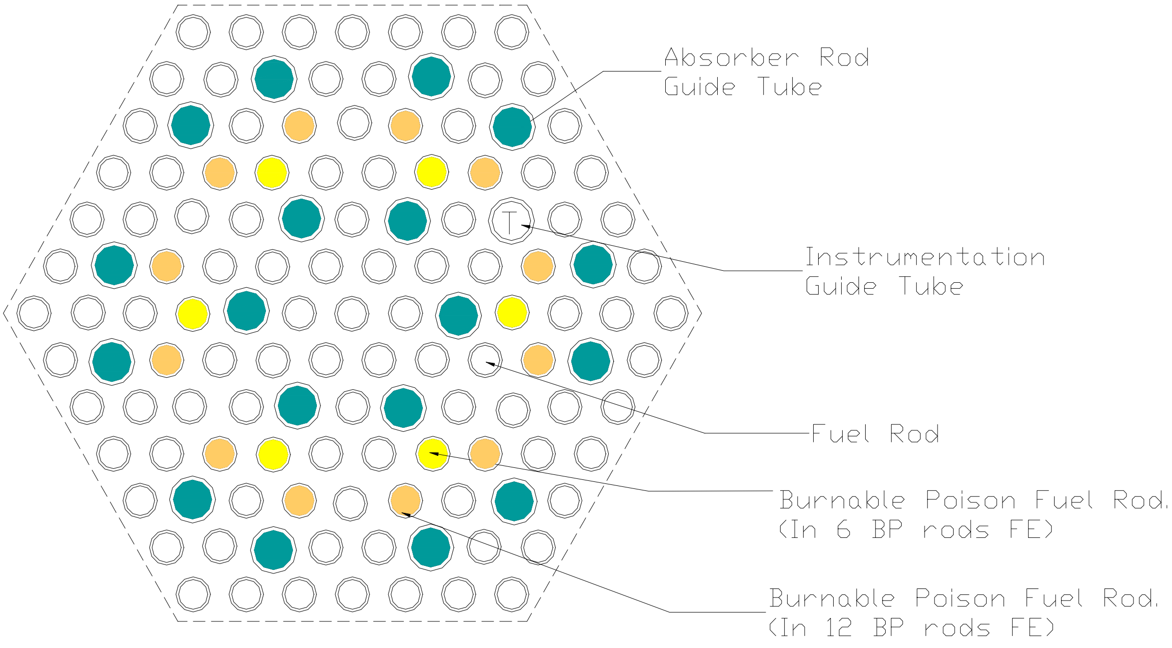

FIG. I–4. Fuel assembly diagram: fuel rods, guide thimbles and instrumentation thimble distribution. BP: burnable poison; FE: fuel element.

In order to achieve a sufficiently uniform pressure loss and superheating on the secondary side, the length of all tubes is equalized by changing the number of tubes per coil layer. Thus, the outer coil layers will hold a larger number of tubes than the inner ones. Owing to safety reasons, steam generators are designed to withstand the primary pressure without pressure on the secondary side, and the whole live steam system is designed to withstand the primary pressure up to the isolation valves (including the steam outlet/water inlet headers) for the case of a steam generator tube rupture. The natural circulation of the coolant produces different flow rates in the primary system according to the power generated (and removed). Under different power transients, a self-correcting response in the flow rate is attained [I–3].

Owing to the self-pressurization of the RPV (steam dome), the system maintains the pressure very close to the saturation pressure. In all operating conditions, this has proved to be sufficient to guarantee remarkable stability of the RPV pressure response. The control system is capable of keeping the reactor pressure practically at the operating set point through different transients, even in the case of power ramps. The negative reactivity feedback coefficients and the large water inventory of the primary circuit, combined with the self-pressurization features, make this behaviour possible with minimum control rod motion. It could be concluded that the reactor has outstanding performance in operational transients.

I–13.2. Safety systems

The CAREM safety systems are based on passive features and should guarantee no requirement for operator interventions to mitigate accidents during a long period (Fig. I–5). They are duplicated to fulfil the redundancy criteria. The shutdown system is diversified to fulfil the regulatory requirements.

The FSS is designed to shut down the core when an abnormality or a deviation from normal situations occurs, and to maintain the core as subcritical during all shutdown states. This function is achieved by dropping a total of 25 neutron absorbing elements into the core under the action of gravity. Each neutron absorbing element is a cluster composed of a maximum of 18 individual rods that are bound together in a single unit. Each unit fits well into the guide tubes of each fuel assembly.

Hydraulic control rod drives (CRDs) avoid the use of mechanical shafts passing through the RPV, or through the extension of the primary pressure boundary, and, thus, eliminate any possibility of a large loss of coolant accident (LOCA), since the whole device is located inside the RPV. Their design is an important development in the CAREM concept [I–12]. Out of the 25 CRDs (their simplified operating diagrams are shown in Fig. I–6), 6 are the FSS. During normal operation, they are kept in the upper position, where the piston partially closes the outlet orifice and reduces the water flow down to a small leak. The CRD of the adjustment and control system is a hinged device, controlled in steps, fixed in position by pulses over a base flow, and designed to guarantee that each pulse will produce only one step.

Both types of device perform the scram function based on the same principle: gravity driven rod drop when the flow is interrupted, so malfunction of any powered part of the hydraulic circuit (i.e. valve or pump failures) will cause an immediate shutdown of the reactor. The CRDs of the FSS are designed using a large gap between the piston and the cylinder in order to obtain a minimum dropping time, thus taking a few seconds to insert the absorbing rods completely into the core. For the adjustment and control system, the CRD manufacturing and assembling allowances are stricter, and clearances are narrower, but there is no stringent requirement on drop time.

The second shutdown system is a gravity driven injection device of borated water at high pressure. It actuates automatically when the reactor protection system detects a failure of the FSS or in the case of a LOCA. The system consists of two tanks located in the upper part of the containment. Each is connected to the reactor vessel by two pipelines: one from the steam dome to the upper part of the tank, and the other from a position below the reactor water level to the lower part of the tank. When the system is triggered, the valves open automatically, and the borated water drains into the primary system driven by gravity. The discharge of a single tank produces complete shutdown of the reactor.

The residual heat removal system has been designed to reduce the pressure in the primary system and to remove the decay heat in the case of a loss of the heat sink. It is a simple and reliable system that operates by condensing steam from the primary system in the emergency condensers. The emergency condensers are heat exchangers consisting of an arrangement of parallel horizontal U tubes between the two common headers. The top header is connected to the reactor vessel steam dome, while the lower header is connected to the reactor vessel at a position below the reactor water level. The condensers are located in a pool filled with cold water inside the containment building. The inlet valves in the steam line are always open, while the outlet valves are normally closed; therefore, the tube bundles are filled with condensate. When the system is triggered, the outlet valves open automatically. The water drains from the tubes, and steam from the primary system enters the tube bundles and is condensed on the cold surface of the tubes. The condensate is returned to the reactor vessel, forming a natural circulation circuit. In this way, heat is removed from the reactor coolant. During the condensation process, the heat is transferred to the water of the pool by a boiling process. This evaporated water is then condensed in the suppression pool of the containment.

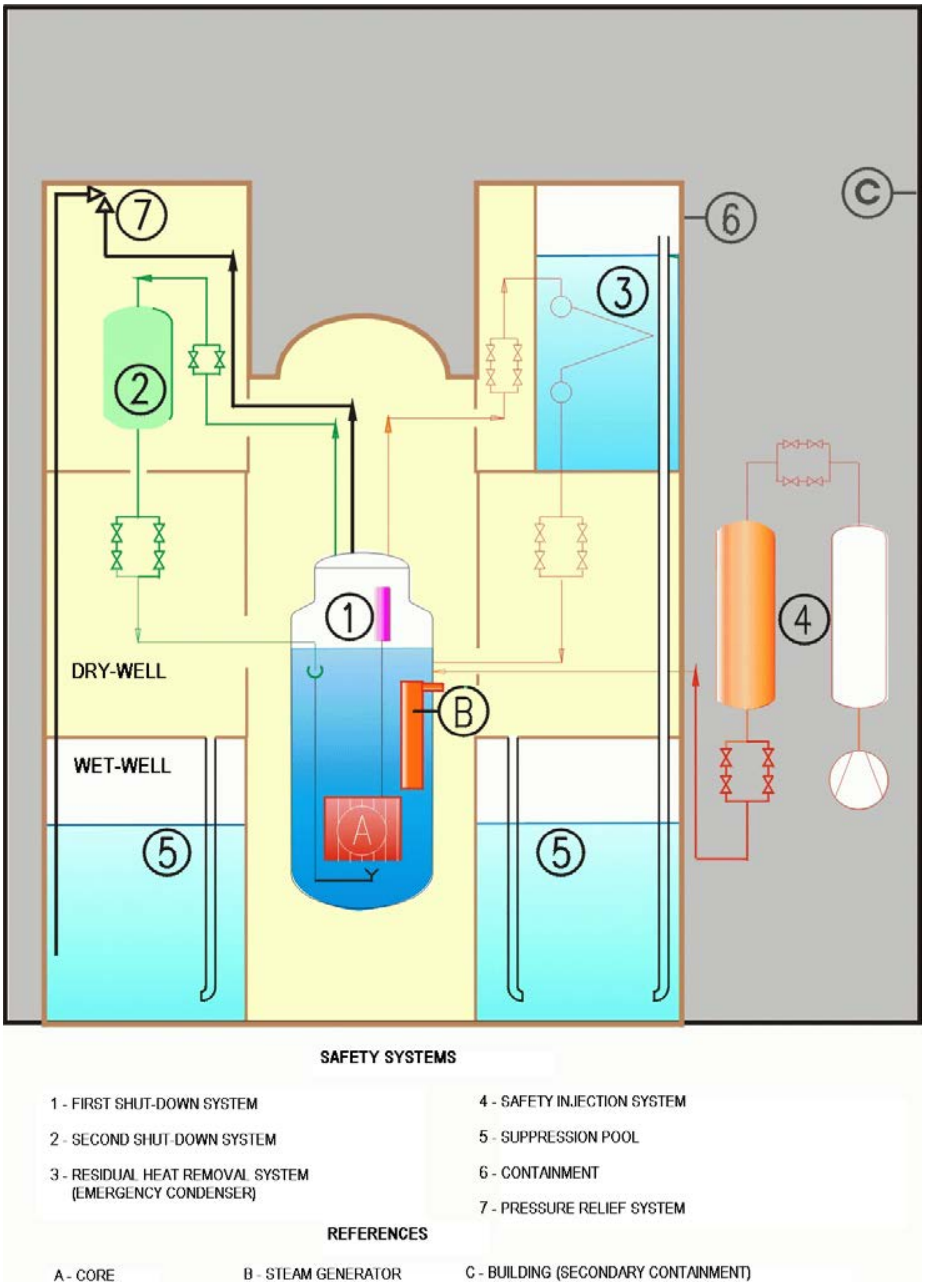

FIG. I–5. Containment and safety systems.

The emergency injection system prevents core exposure in the case of a LOCA. In the event of such an accident, the primary system is depressurized with the aid of the emergency condensers to less than 1.5 MPa, with the water level remaining over the top of the core. At 15 MPa, the low pressure water injection system comes into operation. The system consists of two tanks with borated water connected to the RPV. The tanks are pressurized, thus, when during a LOCA, the pressure in the reactor vessel reaches 15 MPa, the rupture discs break and flooding of the RPV starts.

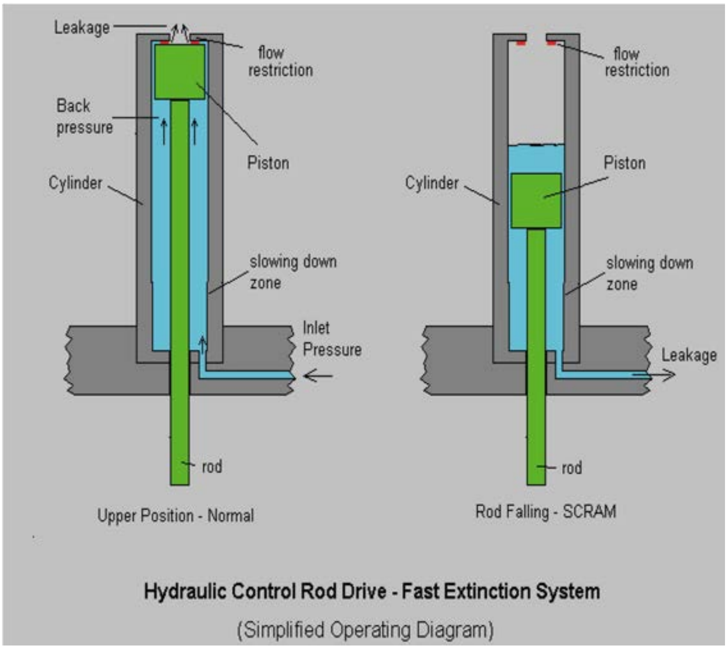

FIG. I–6. Simplified operating diagram of a hydraulic control rod drive (fast shutdown system).

Three safety relief valves protect the integrity of the RPV against overpressure, in case of a significant misbalance between the core power and the power removed from the RPV. Each valve is capable of producing 100% of the necessary relief. The blowdown pipes from the safety valves are routed to the suppression pool.

The primary system, the reactor coolant pressure boundary, the safety systems and the high pressure components of the reactor auxiliary systems are enclosed in the primary containment — a cylindrical concrete structure with an embedded steel liner. The primary containment is of a pressure suppression type, with two major compartments: a dry well and a wet well. The dry well includes a volume that surrounds the RPV and the second shutdown system rooms. A partition floor and a cylindrical wall separate the dry and wet wells. The lower part of the wet well volume is filled with water, which acts as a condensation pool, and the upper part is a gas compression chamber.

Several initiating events were considered in the accident analysis performed for CAREM-25. They can be grouped into reactivity insertion, loss of heat sink and LOCA [I–4]. As there are no primary pumps, a total loss of flow accident is not applicable to the CAREM-25 case.

As a general conclusion, after accident analysis, it could be said that, due to the large coolant inventory in the primary circuit, the system has a large thermal inertia and a long response time in the case of transients or severe accidents.

I–13.3. Advantages of the CAREM design

The CAREM design is expected to offer the following technical and economic advantages compared to traditional PWR designs:

- No need to use safety systems for dealing with a large LOCA, owing to the absence of large diameter piping associated with the primary system. The size of the maximum possible break in the primary system is only 38 mm.
- Central rod ejection accidents are essentially eliminated owing to the use of the developed innovative hydraulic mechanism that is completely located inside the RPV. Furthermore, the hydraulic CRD mechanism has a lower cost compared to the CRD mechanisms of present day PWRs.
- Large coolant inventories provided in the primary circuit, resulting in a large thermal inertia and a long response time in the case of transients or accidents.
- Shielding requirements reduced by the elimination of gamma sources.

- Large water volumes provided between the cores and the vessel walls, leading to very low fast neutron doses over the RPV walls.
- Primary pumps and pressurizers eliminated, resulting in lower costs, increased safety and advantages for maintenance and availability.

I–13.4. Plant design

The CAREM nuclear island is placed inside a containment system, which is designed to secure pressure suppression to contain the energy of the reactor and cooling systems, and to prevent a significant fission product release, in the event of accidents.

The building surrounding the containment has been designed on several levels, and it is placed on a single reinforced concrete foundation mat. The mat supports all structures of the same seismic classification, allowing an integration of the RPV, the reactor safety and auxiliary systems, the spent fuel pool and of other related systems in one single block. The plant building is divided into three main areas: the control module, the nuclear module and the turbine module.

Finally, the CAREM nuclear power plant uses a standard steam cycle of simple design for power conversion.

I–14. CAREM DEVELOPMENTS

The concept of design cycles has been applied in different frameworks involving several steps from conceptual design to the final product (system, equipment, design code or technology process) capable of meeting the specific requirements. From the early stages of the CAREM project, an engineering approach was adopted sequentially. There were two stages in the design:

(a) Conceptual/basic design and experimental activities as an aid to design;
(b) Detailed design and experimental activities for validation/qualification of the design.

Current activities are carried out in order to construct and operate a prototype plant, CAREM-25, which will serve as a demonstration plant of the CAREM concept.

Within the CAREM project, effort has been focused mainly on the nuclear island, located inside the containment, and the safety systems where several innovative design solutions required developments of the first stage (a), to ensure that they comply with the functional requirements. This is attributed mainly to the reactor core cooling system (RCCS), the reactor core itself and the fuel assembly, the reactor pressure vessel internals (RPVIs) and the FSS. An extensive experimental plan has been prepared, including the design and construction of several experimental facilities to fulfil the requirements of the project.

Some systems/devices of CAREM require developments limited to the second stage (b) of a design cycle (qualification, or just adaptation of a proven solution). This means that they are not actually innovative by their features, but require certain development efforts in order to be fit for the project engineering.

RCCS modelling and qualification are boosted by the tests performed in a high pressure natural circulation rig (CAPCN), covering thermal-hydraulics and reactor control and operating techniques. The CAPCN rig reproduces all of the dynamic phenomena of the RCCS, except for 3-D effects.

The core design involves different aspects, i.e. the study of thermal limits, neutronic modelling, structural mechanical design and fuel assembly design. Neutronic modelling requirements may be covered by benchmark data available worldwide and by the data from the RA-8 critical facility. For fuel element design, the CNEA has vast experience in the technology of nuclear fuel, and relevant structural and hydrodynamic tests are being carried out in low and high pressure rigs.

To test the mechanical design of the core (structural, dynamic, seismic, etc.) and other RPVIs, mock-up facilities are being constructed. They represent sections of the core, and include one vertical full scale model with the supporting barrel and its kinematics chain.

The FSS, or more specifically the CRDs, are a good example of an innovative device design, comprising all of the design cycle stages. An experimental plan is under way for the design and qualification stages.

Brief descriptions of some of the most relevant development tasks and the facilities at which the tests are being carried out or are planned as part of the CAREM project are given in the following.

I–14.1. Dynamic tests of RCCSs

The main purpose of the natural convection high pressure loop CAPCN is to study the thermal-hydraulic dynamic response of the CAREM primary loop, including all coupled phenomena that could be described by 1-D models. This includes the validation of the calculation codes on models of a rig, and the extension of validated models to the analysis of the CAREM reactor. Activities were performed and are ongoing in order to validate the thermal-hydraulic tools used in the design.

The CAPCN rig (see Fig. I–7) resembles the CAREM primary loop (with self-pressurized natural circulation) and the steam generator (helical once through type), while the secondary loop is designed only to produce adequate boundary conditions. Operational parameters are reproduced for the intensive magnitudes (pressure, temperature, void fraction, heat flux, etc.) and scaled for the extensive magnitudes (flow, heating power, cross-sections, etc.). The height was kept approximately to a 1:1 scale.

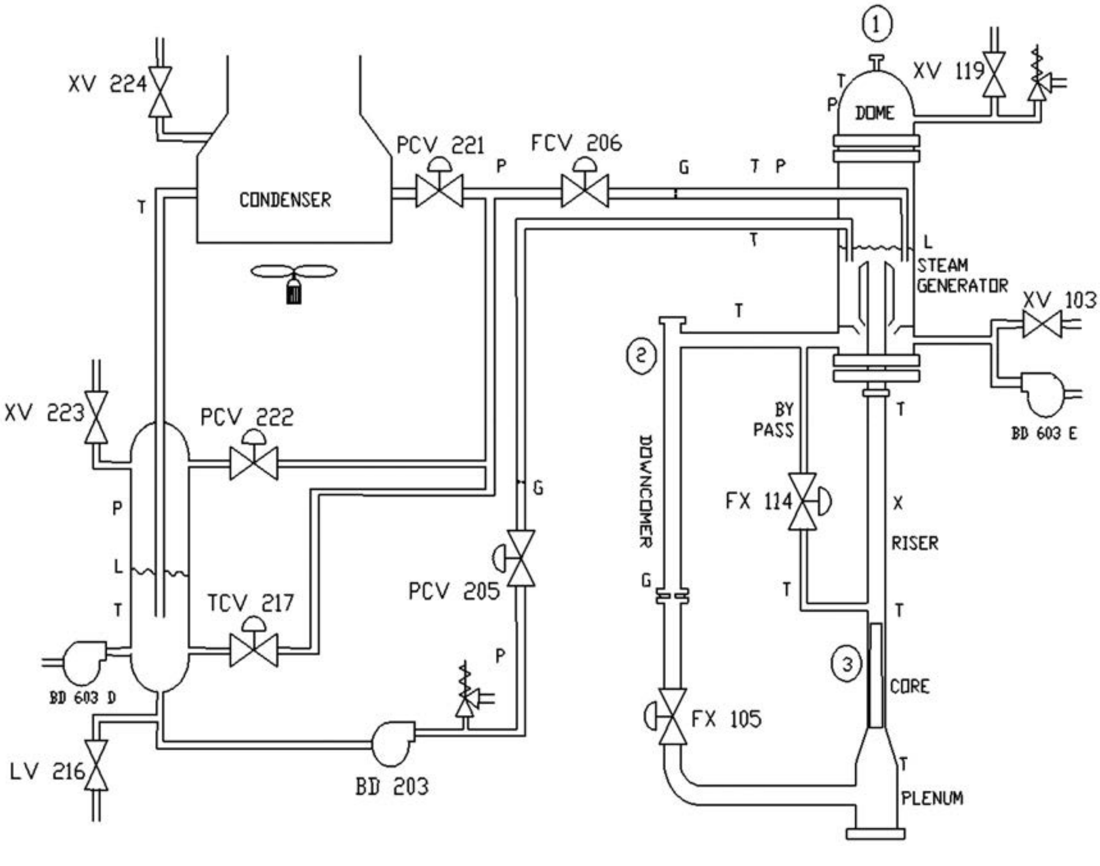

FIG. I–7. CAPCN simplified process and instrumentation diagram.

The heating power may be regulated up to 300 kW, by the operator or by a feedback loop on the primary pressure.

The secondary loop pressure and cold leg temperatures are controlled through valves. The pump regulates the flow. The condenser is of an air cooled type with airflow control.

The control of the actuators (heaters, valves, pumps, etc.), the data acquisition and the operating follow-up are carried out from a control room, through computer based, multinode software (flexible enough to define any feedback loop).

Most of the tests [I–13] consist of an initial self-steady state in which a pulse-wise perturbation induces a transient.

I–14.2. Critical heat flux tests and thermal limits

The thermal-hydraulic design of the CAREM reactor core was made using an improved version of the 3-D, two fluid THERMIT code. In order to take into account the strong coupling of the thermal-hydraulics and the neutronics of the core, THERMIT was linked with the neutronic code CITVAP. This coupled model allows the 'drawing' of a 3-D map of power and thermal-hydraulic parameters at any stage of the burnup cycle.

The prediction of the thermal limits (to harmful phenomena such as critical heat flux) of the fuel elements during operation and transients is considered of utmost importance.

Mass flow rate in the core of the CAREM reactor is rather low compared to typical light water reactors and, therefore, the correlations or the experimental data available are not completely reliable in the range of interest. For this reason, the analytical data must be verified by ad hoc experiments.

The experiments were conducted at the thermal-hydraulic laboratories of the Institute of Physics and Power Engineering (Obninsk, Russian Federation).

The main goal of the experimental programme [I–6] was to generate a substantial database to develop a prediction methodology for critical heat flux applicable to the CAREM core, covering a wide range of thermal-hydraulic parameters around the point of normal operation of CAREM-25.

Most of the tests were performed using a low pressure Freon rig, and the results were then extrapolated to water conditions through scaling models. Finally, a reduced set of tests were performed with water at high pressure and temperature, to validate the method for scaling.

Different test sections were assembled to simulate different regions of the fuel element as well as radially uniform and non-uniform power generation. A bundle with 35% of the full length was tested to obtain critical heat flux data under average subcooled conditions. More than 250 experimental points under different conditions were obtained in the Freon loop, and more than 25 points in the water loop.

I–14.3. Fuel assemblies

The activities for this subject mainly covered the two following issues:

- Improvement and extension of the simulation models of the BACO ('barras combustible', fuel rods in Spanish) computational code, which fits under the first stage (a) of the design cycle;
- Verification, evaluation and qualification of the designs of fuel assemblies, which fits under the second stage (b) of the design cycle.

The BACO code [I–7] produces a best estimate computer simulation of the principal thermomechanical phenomena that occur within a nuclear fuel rod during the burnup process. It addresses generation and migration of fission products, fission gas release, in-clad pressure buildup, pellet deformation, crystallographic grain growth, stress–strain evaluation, evaluation of pellet cladding interactions, etc.

This code has already been developed and verified against the data of the fuel assemblies of PHWRs produced in Argentina. In order to cover fuel assemblies with the enriched uranium fuel, some new models were introduced, and others were modified. These include the influence of high burnup on thermal conductivity of UO_2, the thermal conductivity in the pellet cladding gap (the impact of Xe at high burnup) and the migration of porosity (densification and restructuring).

The above mentioned new models were validated through the participation in a coordinated research project (CRP) of the IAEA [I–8]. This CRP, called the Fuel Modelling at Extended Burnup (FUMEX) programme, fostered validation by initially sharing the experimental information of operating conditions and requirements of a certain fuel, and then by comparing blind simulation results with the experimental measurements.

The BACO code, combined with the database of international fuel performance experiments (Organisation for Economic Co-operation and Development/Nuclear Energy Agency), is expected to cover the validation and evaluation requirements of the fuel rod design.

The fuel assemblies (see Fig. I–8) and the absorbing clusters have been subject to a series of qualification tests, including standard mechanical evaluations and hydraulic tests. The latter comprise:

- Tests in a low pressure rig evaluating pressure losses, flow induced vibrations and general assembly behaviour;
- Endurance tests in a high pressure loop to evaluate wear out and fretting processes.

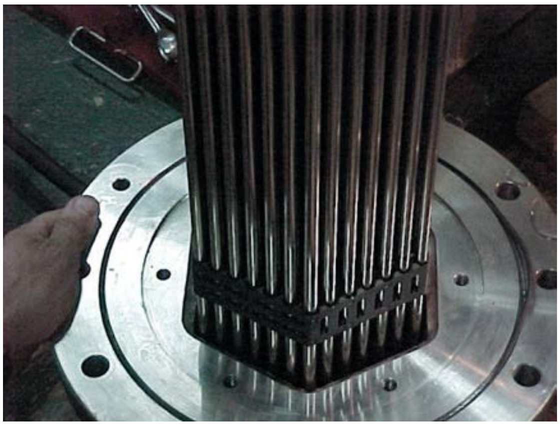

FIG. I–8. Fuel assembly entering a low pressure rig for the evaluation of pressure losses.

I–14.4. Neutronic tests and benchmarking

The RA-8 has been designed and constructed as an experimental facility to measure neutronic parameters typical of the CAREM core.

It provides a reactor shielding block and a reactor tank that can be adapted to hold custom designed reactor cores.

Experiments were performed using fuel rods with the same radial geometry and pitch as the CAREM-25 fuel element.

Components of the neutronic calculation lines were validated for a hexagonal geometry using experimental data from the ZR-6 research reactor (Central Research Institute for Physics, Academy of Sciences, Hungary), as well as for a square geometry using PWR critical experiments.

I–14.5. Hydraulic CRD tests

One of the most innovative systems of the CAREM concept is the hydraulic (in-vessel) control rod drive (HCRD). For HCRDs, two designs are under development: the fast extinction and the adjustment and control CRDs, with the latter presenting major challenges related to the design.

The design incorporates mechanical and thermal-hydraulic innovative solutions, so that the feasibility of the concept must be demonstrated first, before reactor engineering is started. On the other hand, judging by their operational functions (the adjustment and control, and fast extinction of the chain reaction), the HCRDs are part of one of the most important safety systems of the reactor: the FSS. These two features indicate that the HCRD design should have been supported by a comprehensive experimental programme including experiment aided design and qualification tests. The design objective was to ensure high reliability of HCRDs with reasonably low maintenance requirements.

The development plan provided for four distinct stages and included the construction of several experimental facilities, to gradually attain test conditions similar to RPV operating conditions. The four different stages and associated facilities were the following.

I–14.5.1. Preliminary tests (conceptual verification)

The aim of this test was to prove the feasibility of the theoretical approach, to have a first idea of some of the most sensitive controlling parameters, and to determine spot points to be focused upon during design. Tests were undertaken on a rough device and produced promising experimental results. Good agreement with the first modelling data was obtained.

I–14.5.2. First prototype tests

This stage was devised to determine preliminary operating parameters of a full scale mechanism, as a first step towards detailed engineering. The parameters included flow ranges, modes of producing hydraulic pulses, etc. Manufacturing hints that simplified and reduced the costs of the first design were also found. Tests were carried out in a test rig and, as part of this experimental development, it was decided to assign the regulation and fast drop functions to different devices.

I–14.5.3. Low pressure CRD rig

This stage was carried out with the CRDs at atmospheric pressure, and with feedwater temperature regulation up to low subcooling. The feedwater pipeline simulated alternative configurations of the piping layout with a second injection line (dummy) to test possible interference of the pulses.

The ad hoc test rig (‘circuito de ensayo de mecanismos’, Fig. I–9) was designed to allow automatic control of the flow, pressure and temperature, and its instrumentation produces information on operating parameters, including pulse shape and timing. The tests included the characterization of the mechanism and the driving water circuit at different operating conditions, and the study of abnormal situations such as an increase in the drag forces, pump failure, loss of control over water flow or temperature, saturated water injection, suspended particle influence and pressure ‘noise’ in the feed line.

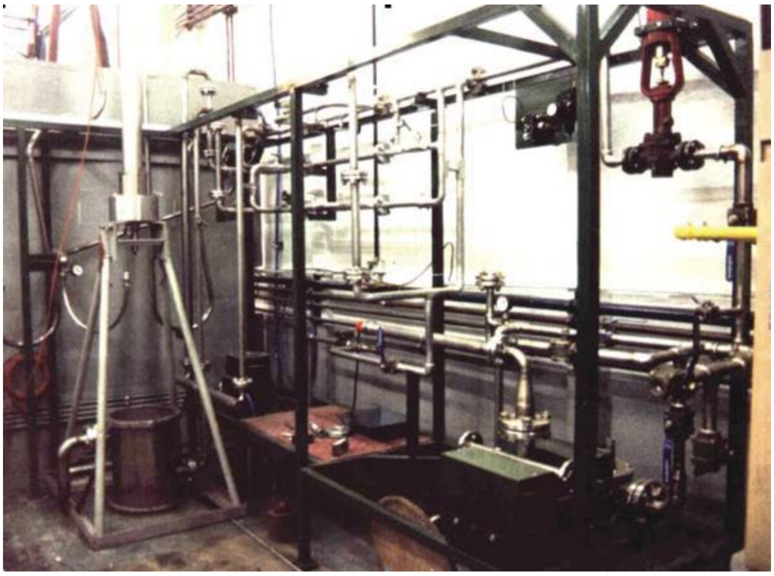

FIG. I–9. Low pressure mechanism test rig.

The tests were carried out under turbulent regime conditions, which are the conditions closest to the operational ones, as obtained in this loop. The tests showed good reliability and repetitiveness, and produced sensitivity margins for the relevant variables within the control capabilities of a standard system.

I–14.5.4. Qualification tests

A high pressure loop (‘circuito de alta presión para ensayo de mecanismos’) was designed and is being constructed in order to reach the actual operating conditions ($P = 12.25$ MPa, $T \approx 326$°C). The main objectives were to verify the behaviour of the mechanisms, to tune up the final controlling parameter values and to perform endurance tests. After this stage, testing of the system under abnormal conditions, such as RPV depressurization, simulated rupture of feeding pipes, etc., will be performed.

I–14.6. RPVI tests

The mechanical structure of the core, including the supporting guides and all parts of the cinematic chain of the FSS, are of particular interest. Complex assemblies and structures, such as the steam generator units, or ad hoc mechanical solutions, require an evaluation of the manufacturing and assembly process, before finishing the design stage.

In short, the RPVIs must be verified in order to define the manufacturing and assembly allowances, and other detailed engineering parameters, ensuring that the internals would comply with their function during the RPV lifetime. Most of the tests are performed on mock-up facilities at 1:1 vertical scale.

I–14.7. In-vessel instrumentation

As the HCRD design adopted has no movable parts outside the RPV, it was necessary to design a special probe to measure the rod position. The probe had to be able to withstand the operating conditions of the primary circuit. The proposed design consists of a coil wired around the HCRD cylinder with an external associated circuit that measures the electric reluctance variations induced by a movement of the piston shaft (made of magnetic steel) inside the cylinder.

The cold tests performed have shown that the system is capable of sensing one step movement of the regulating CRD, with an acceptable accuracy. In-furnace high temperature tests are going to be conducted to evaluate the behaviour of the system under temperature changes similar to those occurring during operation transients.

The design of a special high pressure removable feedthrough to allow the passage of dozens of electrical signals through the RPV cover is also under development. It includes the development and qualification of specific manufacturing and welding techniques.

I–15. ECONOMIC EVALUATION TOOLS

Designing a reactor is an intrinsically complex task due to the quantity of parameters whose dimensions have to be determined and the existing relations between them. At a conceptual engineering stage, quantifying the influence of the mechanics, thermal-hydraulics, neutronics and safety performance on the reactor costs is of interest. A break-down of the main items that affect costs should be identified, with the purpose of finding a unit cost for the generated energy, a figure of merit for comparing the alternative designs.

Under the programme of the CAREM integral type reactor, a computational tool was developed to perform the above mentioned economic evaluations as support to the design team during the conceptual design stage. This tool makes the necessary internal iterations to obtain a coherent set of design and operation parameters that define a reactor, taking into account the main feedback existing between these parameters. The code also allows the designers to optimize economically the most important parameters of the core, primary circuit, safety systems and secondary systems, in order to reduce the cost of electricity generation [I–9, I–10].

The economy of different power modules of the CAREM was analysed. Two primary circuit circulation options were considered: natural circulation and assisted convection. For low powered modules (below 150 MW(e)), both options give similar results, and the natural circulation option becomes preferable; for higher powered modules (up to about 300 MW(e)), the assisted circulation option is more economical and feasible.

I–16. CIRCULATION ASSISTANCE

Different circulation options are being considered for circulation assistance. As an example, the use of jet pumps was analysed because the CAREM configuration has many similarities with boiling water reactors, and the jet pumps can be located in the downcomer region below the steam generators [I–11]. The value of the driving flow for each jet pump is limited by the maximum size of the penetrations allowed in the RPV in order to limit the magnitude of the LOCA. In turn, this limits the power range for which such an option could be applicable.

Another important aspect is the length of the jet pumps, and the analysis of whether there is enough space to locate them in the proposed region. Different models were considered to estimate the total length of the jet pumps. However, due to uncertainties, the requirement of an experimental programme to study mixing in the mixing chamber was identified. A low pressure rig has been constructed to study the hydrodynamics of the mixing section, but more experimental data are necessary to define and validate the required length of the jet pumps.

I–17. IMPLEMENTATION OF SAFEGUARDS

Two isolated material balance areas (MBAs) for irradiated fuel are included in the CAREM design concept in order to facilitate safeguards implementation and reduce the safeguards costs. One is the pressure vessel and the other is the spent fuel pool. These two MBAs contain all of the irradiated fuel and allow integrity checks by remote systems. During reactor operation, there is no physical way to gain access to this fissile material.

To increase proliferation resistance, all refuelling operations will be carried out in the reactor hall, which is designed to allow remote monitoring of all nuclear material handling. The entrance/exit and the interfaces have been designed to allow the counting of items during their movement.

The selected approach allows a reduction of the safeguards costs by about 10–20% [I–13].

I–18. LONG LIFE CORES

Different refuelling interval options were analysed in the conceptual analysis of the CAREM-300 once through fuel cycle [I–14]:

- Increased fuel enrichment;
- Lower core power density;
- Both of the above.

It was found that, for the present market conditions, the fuel cost resulting from increased refuelling interval is much higher than for the reference design (it becomes particularly expensive when higher discount rates typical for developing countries are used in the analysis).

I–19. ASSESSMENT OF THE NUCLEAR DESALINATION OPTION

The evaluations were performed for a region located in the central coastal area of the Argentinian Patagonia, Puerto Deseado. This region is known to suffer from a severe scarcity of water.

A CAREM nuclear power plant coupled with the reverse osmosis process was found to be an attractive, economical and technically feasible option, as well as a safe and reliable alternative for freshwater production from sea water and energy production in the Puerto Deseado region [I–15].

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Annex II

METHODOLOGIES FOR SYSTEMATIC ASSESSMENT OF DESIGN SIMPLIFICATION

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II–1. INTRODUCTION — THE CHALLENGE OF DESIGN CHANGES AND INNOVATION

Nuclear power plants are sophisticated engineered systems. To achieve a commercial nuclear power plant, its functions, systems and components need to be elaborated from design ideas to technical solutions and to the appropriate hardware over a long period of time. On the way, several design alternatives usually compete for implementation in the final plant. Engineering teams perform assessments, comparing different proposed engineering options in order to select an appropriate solution for the specific plant aimed at specific customers. This is a common process in design evolution.

During such assessments, the trade-offs associated with different options are not always as simple as seen at very early design stages. Any requirement (e.g. relevant to safety, availability or competitiveness) usually has several dimensions; therefore, a change in the design aimed at producing the targeted effect (e.g. simplification of passive safety systems) as a rule produces other effects not directly related to the original idea. It means that the assessment needs to be carried out in iterations, not to bypass any meaningful feedback. The assessment then becomes a challenge for those designers who are interested in exploring innovative approaches and simplified systems.

Unlike in several developed countries, so far, nuclear energy has been only marginally used in small and medium sized developing countries. One of the important reasons for this has been the lack of competitive commercial nuclear options with small and medium sized reactors (SMRs). Then, the challenge for SMR designers has been to design simpler plants in order to counterbalance the well known penalties of economy of scale.

The lack of experience with SMRs in small and medium sized developing countries could be viewed as practical proof of the lack of commercial success of such reactors. Fossil fuelled gas turbine technologies offer very competitive energy options available from tens to hundreds of MW(e), with relatively small changes owing to the size economy. Therefore, the electricity growth in small and medium sized developing countries has been supported mostly by fossil fuels, with only a few exceptions. Such a situation is a challenge for the nuclear stakeholders in small and medium sized developing countries.

II–2. ADVANTAGES AND DISADVANTAGES OF SIMPLICITY AND INNOVATION

Very complex design feedbacks in a nuclear power plant require that, if a design team wishes to evaluate a trade-off between different alternatives, much engineering effort needs to be applied to take into account all feedback and effects associated with the different options, which typically limits consideration of the design alternatives by a few cases because the comparative assessment process is very expensive in terms of labour, time and money. Such a situation sometimes precludes even the consideration of innovative approaches because the efforts required to perform a detailed evaluation increase with innovation of the alternative.

Many SMR designs being developed currently appear simpler than large nuclear power plants; however, until now, SMRs had not achieved wide recognition as an economically competitive nuclear option. Present SMRs appear to be successful products only for very specific conditions.

Sometimes, engineers are fully aware of the technical challenges and use innovations in order to simplify systems, but it is not always the case that simplicity leads to cheaper designs.

If a cheaper nuclear power plant is the final target, to assume that a simpler system will always produce a cheaper plant is far from the truth. Actually, such assumptions are often supported by very risky design criteria. On the other hand, very detailed studies that could give a true picture are possible only in a few cases, usually involving large companies, because of the required high level of expenses.

Even using a top-down cost evaluation method (scaling the costs of the main components and systems of a plant) requires much engineering effort for each comparative option because the sizes of the main components and systems need to be calculated for a complete plant, and for each design alternative. All cost evaluation methods, top-down approaches or bottom-up approaches, are often treated as milestones in a design project, in which cost assessment is performed based on some outputs of the engineering of the components and systems, and is weakly integrated into the overall design process.

Without finding another approach, the business as usual engineering work will continue to result in a never ending discussion on innovation and conservatism. To overcome this, the first useful step could be to develop a more general approach, not detailed enough to replace the rigorous detailed engineering work, but useful enough to rank the more promising options or alternatives at earlier project stages.

A screening method capable of detecting the weak links and strengths in an SMR design, including the overall effects of different design options, such as simplification, modular construction, etc., could be a useful tool to address the challenges described above.

II–3. METHODOLOGY FOR SIMPLICITY ASSESSMENT

The objective of this methodology is to offer a general approach with enough detail to take into account the main feedback in the economy of a plant, based on cost estimation rather than detailed calculation. The goal is not to replace detailed cost evaluation in the design process, but to develop fast screening methods to identify good candidate options for further development.

If a competitive target is selected and a proper model is in place, which includes the overall scaling model, theoretically, more relevant or first order design feedback could be established in a comprehensive way, if the following general conditions are fulfilled:

- The cost of a design feature, at the level of a component, a system, a plant or a project, is governed by the overall generic scaling model.
- Changing a design feature results in changes to other variables of the overall scaling model of plant economics; it is a combination of the original and the resulting changes that needs to be taken into account when calculating the competitive target.

Based on the above mentioned approach, two functions can be defined and included in the relationship for the overall competitive target.

Then, a method can be developed that, in theory, could compute the overall trade-off, merging the direct saving owing to a certain design change with the resulting impact of this design change (positive or negative) on the overall scaling model and the target. If the model used is too simple or even trivial, the usefulness will be low. However, if a more complete model that includes the construction times, the discount rates and the cross-effects between different systems is used, a more useful tool could be offered.

The validity of the model will depend on the quality of the functions and models used. Then, to achieve a minimum level of detail sufficient to produce useful results, but to carry out the assessment fast enough to obtain timely design screening, the following requirements need to be included in the four elements of the assessment method:

(a) The competitive figure of merit (competitive target) needs to be realistic, such as the levelized unit energy cost (LUEC), and not overly simplified, such as the investment cost ($/kW(e)), because even inclusion of the interest during construction in the specific investment could result in fuel cycle costs that are very different for advanced reactors with different construction times, even if these reactors are otherwise similar. A simplified LUEC model could be a useful competitive target, as will be shown in the following.

(b) The scaling cost model needs to be detailed enough to reflect the impact on the main variables of the proposed design alternatives. Then, very simple scale models linked only to the electrical output are not recommended because many design alternatives may keep the electrical output almost constant while strongly changing other plant components. The scaling model needs to use several independent variables in the scaling.

(c) The design feature cost savings could be easily estimated and calculated by a directly proportional factor that multiplies the item costs, if the users have experience in evaluation of the final costs of the engineered systems or the method is used only to produce a very general screening of different alternatives. If this is not the case, a more detailed model, which includes a break-down of system components, redundancies, and fixed and variable costs, would be required.

(d) The relationship between variables of the scaling cost model could be calculated by introducing appropriate changes in the variables, if the scaling model has been developed comprehensively enough to take into account all of the main external factors not included in the item costs.

II–3.1. Method for advanced design assessment

Using the four requirements above, a simple method is proposed as an example of a tool to be used in the assessment of the trade-offs in advanced nuclear power plant designs related to reduced complexities, improved efficiencies, etc.

To ensure that all four requirements have been considered, each requirement will be related to the other three requirements of the method. Thus, the four elements would be: the competitive target, the scaling model, the feature costs and the models that relate the features to the scaling variables and competitive targets. Short descriptions of the elements and typical analytical examples are provided in the following.

II–3.2. Figure of merit and competitive target

Any realistic economic figure of merit, used as the economic design criterion for a nuclear energy system, could be applied if conditions (b)–(d) given above are met. As LUEC is commonly used in many reports with economic assessments, it will also be used here to derive a detailed model. If other figures of merit are used, a similar detailed calculation procedure needs to be developed, taking into account all necessary details and offering the required completeness.

The LUEC is a well known indicator of generation costs that could be used to compare the generation costs for alternative energy sources, taking into consideration the time dependent costs, investments and incomes. Then, LUEC needs to consider all expenditure profiles during commercial operation, including cash flow for the construction, fuelling, operation and dismantling of the plant, and waste management and refurbishment costs. Plenty of data are required to perform very detailed LUEC calculations. We will limit our consideration to a very simple LUEC calculation, with just enough detail to take into account the main engineering feedback.

The levelized value of the expenditures at time t_0, called $E(t_0)$, can be written using the discount rate r:

$$E(t_0)=\sum_{t=t_{\mathrm{START}}}^{t_{\mathrm{END}}}\frac{\mathrm{CI}_t}{(1+r)^{t-t_0}}+\sum_{t=t_{\mathrm{START}}}^{t_{\mathrm{END}}}\frac{\mathrm{O\&M}_t}{(1+r)^{t-t_0}}+\sum_{t=t_{\mathrm{START}}}^{t_{\mathrm{END}}}\frac{F_t}{(1+r)^{t-t_0}} \tag{II–1}$$

where

CI_t is the capital investment expenditure in time t;
$\mathrm{O\&M}_t$ is the operation and maintenance (O&M) expenditure in time t;

and F_t is the fuel expenditure in time t.

The net power is supplied to the busbar stations, fed into the grid and produces an income from power selling. Assuming that during all of the plant lifetime, a constant real price C of the electricity produced is paid by the consumer, the levelized value of gross income $\mathrm{GI}(t_0)$ at time t_0 can be written as:

$$\mathrm{GI}(t_0)=C\times\sum_{t=t_{\mathrm{START}}}^{t_{\mathrm{END}}}\frac{P_t\times 8766\times \mathrm{Lf}_t}{(1+r)^{t-t_0}} \tag{II–2}$$

where

P_t is the net electrical power of the system in time t;
8766 is the total number of hours in a year;
Lf_t is the load factor in time t;

and C is the constant real price of electricity.

In Eq. (II–2), C is called the levelized lifetime cost, and is defined as the cost per unit of electricity generated, which is the ratio of total lifetime expenses to total expected output, expressed in terms of the present value equivalent. It equals the equivalent average price that would have to be paid by the consumers to exactly repay the capital, O&M and fuel costs, under a proper discount rate. It is also called the LUEC.

In this assessment method, neglecting the feedback from the costs of the backfitting, decommissioning and spent fuel management, the LUEC value after simplification can be calculated as:

$$\mathrm{LUEC} = \frac{\mathrm{CI}_{\mathrm{ON}} + \mathrm{CI}_{\mathrm{IDC}} +}{P \times \mathrm{Lh}_{\mathrm{FP}}} + \frac{\left(\frac{\mathrm{O\&M}}{P}\right)_{\mathrm{FIX}}}{8760 \times \mathrm{Lf}} + \left(\frac{\mathrm{O\&M}}{\mathrm{kW \cdot h}}\right)_{\mathrm{VAR}} + \frac{\left(\frac{\$}{\mathrm{kg}}\right)_{\mathrm{FE}}}{\eta \times \delta_{\mathrm{th}} \times \mathrm{Lh}_{\mathrm{FP}}} + \frac{\left(\frac{\$}{\mathrm{kg}}\right)_{\mathrm{FE}}}{Q \times \eta} \qquad \text{(II–3)}$$

In Eq. (II–3), the capital investment flow CI_t for construction is usually divided into the total overnight cost (also called $\mathrm{CI}_{\mathrm{ON}}$), and the interest during construction ($\mathrm{CI}_{\mathrm{IDC}}$), defined as:

$$\mathrm{CI}_{\mathrm{ON}} = \sum_{j=T_{\mathrm{Ct}}}^{0} \mathrm{CI}_j \qquad \text{(II–4)}$$

$$\mathrm{CI}_{\mathrm{IDC}} = \mathrm{CI}_{\mathrm{ON}} \times \left(\sum_{j=T_{\mathrm{Ct}}}^{0} \omega_j \times (1+r)^j - 1 \right) \qquad \text{(II–5)}$$

where

$\omega_j = \mathrm{CI}_j / \mathrm{CI}_{\mathrm{ON}}$	is the normalized capital investment cash flow;
T_{Ct}	is the construction time, starting after the first payment and ending at the startup of commercial operation;
$\mathrm{Lh}_{\mathrm{FP}} = 8760 \times \mathrm{Lf} \times \left(\frac{1 - \left(\frac{1}{1+r}\right)^{t_{\mathrm{LIFE}}}}{1 - \left(\frac{1}{1+r}\right)} \right)$	is the levelized number of hours at full power;
$\left(\frac{\mathrm{O\&M}}{P}\right)_{\mathrm{FIX}}$	is the fixed O&M cost;
$\left(\frac{\mathrm{O\&M}}{\mathrm{kW \cdot h}}\right)_{\mathrm{VAR}}$	is the variable O&M cost;
$\left(\frac{\$}{\mathrm{kg}}\right)_{\mathrm{FE}}$	is the fuel cost;
η	is the net efficiency of the plant;
Q	is the fuel burnup;

and δ_{th} is the power density of the core in thermal power units per kilogram of the fuel.

Equation (II–3) for LUEC is very simple, but reproduces with high accuracy the results of more complete calculations and takes into account all main aspects that need to be considered in the early design assessment. Such an assessment at the early design stage allows comparison of different design alternatives and evaluation of the advantages and disadvantages of design simplification.

In this equation, the discount rates are not controlled by the designer, and they could be viewed as external values fixed by another player not included in the design process. Other variables, such as the investment cash flow and the plant lifetime, are not related to the direct cost of an item, but can be changed by the designer in the design process; therefore, they could be categorized as project values.

Figure II–1 gives a flow chart of the data required to calculate the competitive target as per Eq. (II–3).

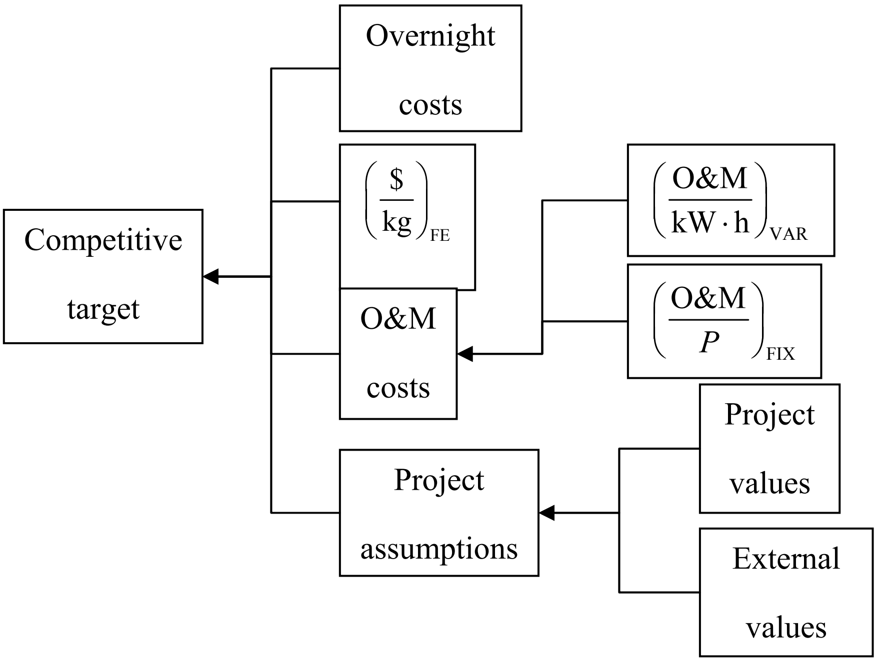

FIG. II–1. Flow chart of the data required to calculate levelized unit energy cost as a competitive target. FE: fuel costs; FIX: fixed; O&M: operation and maintenance; P: unit power; VAR: variable.

II–3.3. Scaling costs model

There is a widely accepted cost account system published by the IAEA, and it is oriented towards the evaluation of economic bids. The break-down used in this system is more related to the typical structure of the suppliers, contractors and subcontractors. For example, reactor plant equipment includes the reactor pressure vessel (RPV) and its internals, the pumps, the pressurizer and the steam generators, together with auxiliary systems and safety systems.

This aggregation scheme includes, in just a few items, many systems that in the design evaluation process change significantly when different design alternatives are evaluated. Therefore, a different cost break-down will be used in the proposed method, which is detailed enough to enable the user to have a minimum level of feedback between different design alternatives and the overnight costs. The cost break-down used is more related to different engineering functions in order to be able to represent different design alternatives.

By comparison with fossil fuel plants, the following items could be considered close to conventional equipment because they can be found in plants of other types based on other technologies:

- Conventional building;
- Turbogenerator system;
- Electrical systems (excluding the generator);
- Condenser or heat transfer to the heat sink;
- Other miscellaneous equipment.

The classical equipment of the nuclear island can be divided as follows:

- Containment or confinement;
- Core vessel;
- Control rods;
- Primary to secondary heat exchangers (steam generators);
- Spent fuel management system;
- Instrumentation and control system;
- Coolant management and control system;
- Primary pumps or compressor, pressure regulation system;
- Other reactor equipment.

The previous two lists of items include all of the main direct cost items, but there are still costs not included in the previous lists, usually called indirect costs. These indirect costs can be divided into:

- Special equipment for reactor mounting;
- Engineering costs;
- Fixed indirect costs;
- Indirect conventional costs;
- Indirect nuclear costs;
- Other indirect costs.

Using these three categories, the overnight costs $\mathrm{CO_{ON}}$ can be calculated as a direct sum:

$$\mathrm{CO}_{\mathrm{ON}} = \sum_{i=1}^{3}\sum_{j=1}^{N_i} I_{i,j} \qquad \text{(II–6)}$$

To have a complete scaling model, each cost item needs to be scaled and modelled in relation to different reactor variables, detailed enough to take into account different design alternatives, but simple enough to be used for fast evaluation and assessment.

A minimum set of variables (V_m) is listed below:

(a) Thermal power (MW(th));
(b) Electrical efficiency (%);
(c) Power density (MW(th)/t heavy metal (HM));
(d) Core vessel weight (t);
(e) Weight of primary to secondary heat exchangers (t);
(f) Volume of the primary system (m^3);
(g) Number of fuel elements;
(h) Core length (m);
(i) Power of primary pumps (MW(e)).

As a good approximation for the proposed model, each of the item costs could be related to at least one variable by an equation of the following type:

$$I_{i,j} = I_{i,j}^{0} \times \left(\frac{V_{i,j}}{V_{i,j}^{0}} \right)^{\gamma_{i,j}} \qquad \text{(II–7)}$$

The variable V_m has been changed to $V_{i,j}$ to clarify that some items are scaled with one of the scaling variables V_m or, in other cases, as a function of several available variables. Thus, the scaling model could include only functions of independent variables:

$$V_{i,j} = V_{i,j}\left(V_m, V_n\right) \tag{II–8}$$

Then, the available item structure could be scaled with those variables (or combinations thereof) that could be related to the more relevant scaling parameter. For example, it is clear that the costs of the electrical systems could be scaled with the electrical power, then $V_{1,3} = V_1 / V_2 = P_{\mathrm{th}} / \eta$, the condenser can be scaled with the thermal power P_{th} rejected to the atmosphere and, then, the condenser scaling variable could be $V_{1,4} = V_1 \times \left(1 - V_2\right) = P_{\mathrm{th}} \times \left(1 - \eta\right)$.

It is clear that if the efficiency η is close to constant, i.e. the changes evaluated do not change the efficiency significantly, both of the above mentioned examples could be scaled with thermal power only.

With this type of model, there is enough flexibility to estimate the cost when the power density is decreased or when the efficiency is increased, while performing a first level evaluation of all of the items that increase or decrease costs. Up to now, one or two variables have been sufficient to build a minimum set of scaling variables per indicator.

If more detailed models of items are required (with other variables and other break-downs of systems and components), the equations and the methods could be extended without significant changes in the overall structure of the method.

The base economic values $V_{i,j}^{0}$ and $I_{i,j}^{0}$ need to be calculated for the original design cost estimate; then, their values depend on the country conditions, currency exchange rates, national policies, etc. Thus, there are no universal values for item costs, but, in general, there is a tendency to have cost distributions consistent among different reactors. Then, the assessment methods are slightly less dependent on the economic values in a country compared to the costs of the items themselves.

Figure II–2 shows a schematic flow chart for the overnight cost calculation, depending on the input of n variables, the initial base costs and the scaling coefficient.

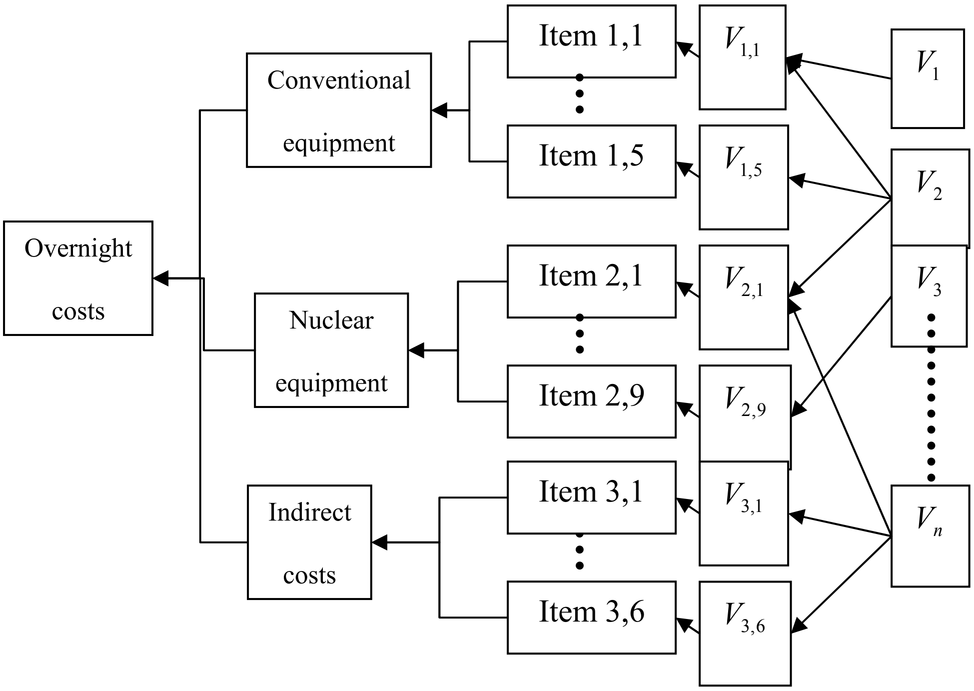

FIG. II–2. Schematic flow chart for overnight cost calculation.

II–3.4. Design feature cost savings

When a simplification scheme is proposed, the usual idea of the designer is to reduce one of the cost items of the plant. The cost reduction could be produced by changing the size of the components, the redundancies or the number of components, via assigning a lower safety classification, etc.

The targeted cost reduction is usually in one item or, in some cases, in more than one. Typically, the design team has a clear understanding of the potential cost savings owing to a design change. In other cases, the idea is still in its preliminary stage, and in such cases, the designer needs to evaluate potential cost savings in the relevant item. To calculate the saving, it is sufficient to evaluate the proportional changes in the cost item because it is the value of a relative change that is required to perform the assessment.

Written as a saving in the item costs, any design change d_k can be represented as a factor $K_{i,j}^{d_k}$ used to multiply the relevant cost item $I_{i,j}$. Thus, Eq. (II–6) changes to:

$$\mathrm{CO_{ON}} = \sum_{i=1}^{3}\sum_{j=1}^{N_i} I_{i,j} \times K_{i,j}^{d_k} \tag{II–9}$$

In the case when there is more than one design change, the *K* factor needs to be estimated for all of the design changes applied together. If several saving factors *K* are applied to a single item, it is assumed that the savings could be independently applied to the system, which is usually not the case. For example, if a pump has been eliminated, this pump is not available for the next design change applied to the same item. As it is very difficult to obtain a precise value of the *K* factor, the value used can represent a guess or a number that could change within a given range because, sometimes, it is more accurate to estimate upper and lower limits for the *K* factor than to estimate the *K* factor itself.

II–3.5. Scaling cost relationship

If the proposed change does not affect any other item or project value or system performance, the method would give a direct fast estimate of the change in the LUEC. Such a case is simple. However, there are few innovative features that would fit into such a case. Moreover, SMRs may require higher levels of innovation in order to improve the economics already hampered by small scale economy. It, therefore, becomes important to relate each design change or changes with all of the variables V_m that have been listed:

$$V_m = V_m(d_k) \tag{II–10}$$

A schematic flow chart illustrating the impact of a design change on the scaling variables and the saving is given in Fig. II–3.

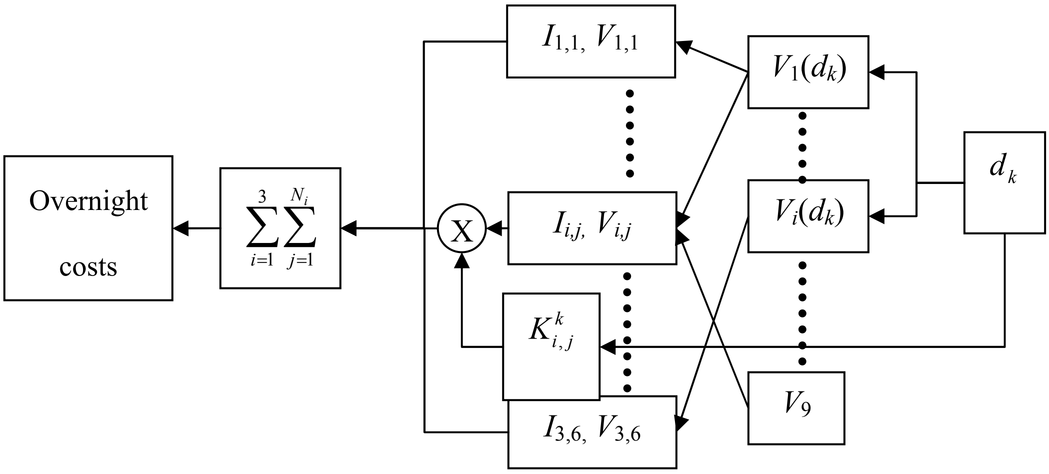

FIG. II–3. Schematic flow chart of the changes in the item cost break-down induced by a single design change d_k.

Figure II–3 shows how a given design change may modify the overnight cost via several routes in addition to the originally anticipated saving factor K. All in all, there is a trade-off, and it is not a priori obvious what the actual cost saving would be.

Moreover, it is not unusual that a given design change influences not only the overnight costs, but the fuel cycle costs (which could require changing the enrichment, the power density or the fuel burnup), the O&M costs (which could result in changes of variable or fixed costs) or the project assumptions such as the construction time. Figure II–4 schematically illustrates these types of feedback.

Figure II–4 also shows that a design change could not affect the external project values because these are the variables that cannot be changed by the designer. However, the external values could be changed by the potential user in order to study whether there could be a trade-off between the external assumptions and the proposed design alternative. Sometimes, there can be innovations that are applicable in a certain investment environment, and are not applicable in other environments. For example, if the discount rate is very high, the expensive first core load could outweigh the low refuelling cost. Generically, there is a certain limit in the discount rate above which this would happen.

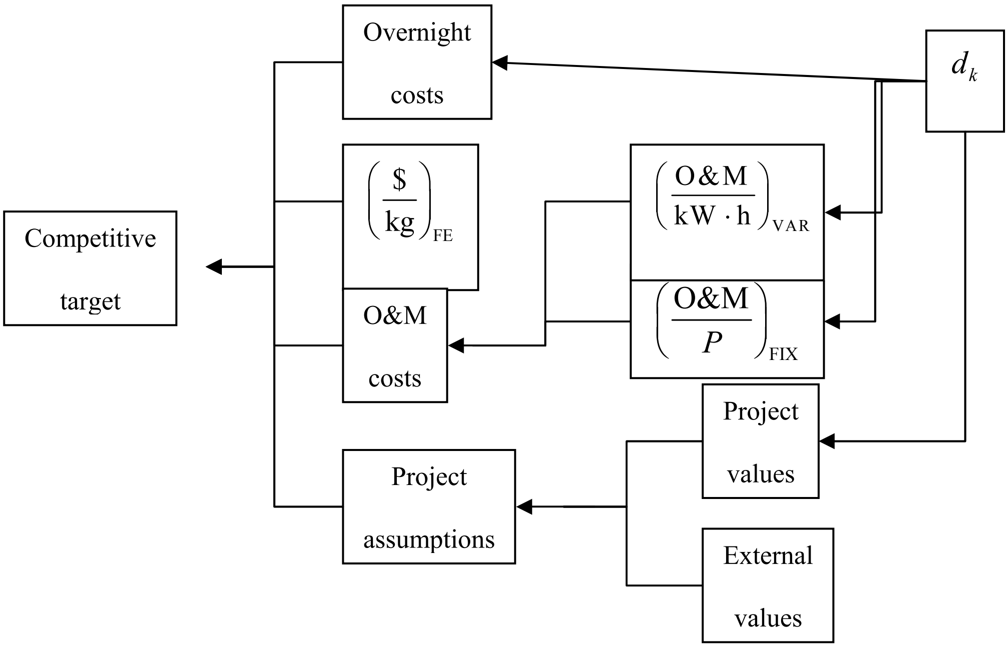

FIG. II–4. Schematic flow chart for overall competitive target calculation for a single design change d_k. FE: fuel costs; FIX: fixed; O&M: operation and maintenance; P: unit power; VAR: variable.

II–4. APPLICATION EXAMPLES

The proposed method could be used to carry out fast first order evaluations of the economic strengths and weaknesses of a design change proposed for a given reactor concept, e.g. that aimed at design simplification.

The method could also be used to study the economy of scale of a given reactor concept, but in a method that is more detailed than just a simple scaling by the electrical power. The method would help determine feedback produced by scaling of different items and, in this way, would provide useful information about the economic strengths and weaknesses of the design.

The method could be applied in reverse, i.e. with the competitive target being fixed, and the inverse calculations being carried out to determine the savings in different items required to achieve the fixed target.

These three possible applications of the model will be illustrated on simple examples, not aiming to prove the method’s ultimate validity, but just used to demonstrate how the method works.

The classical economy of scale example will be a comparison of the scaled up and down versions of an advanced pressurized water reactor (PWR), based on data widely available in the open literature.

Another example will show how the method can be applied to a problem with a fixed competitive target (for a PWR) to analyse the design and find ways of achieving the specified economic target via applying different design strategies.

Yet another example will be about a reactor concept that attempts to drastically reduce the civil works and construction time by designing the plant in modules transported by train.

II–4.1. Classical economy of scale example

If a reactor design is fixed, increasing the power usually decreases the reactor costs. The conventional method to estimate cost reduction is to scale up the overnight cost using published data on scaling coefficients, which are specific to certain reactor designs. The scaling variable is the electrical power output of the plant.

Another standard method is to scale up the reactor cost using the cost break-down for a given design, and to use the published scaling coefficients (e.g. provided by the IAEA) for a standardized cost break-down. As in the previous case, the coefficients depend on reactor type, and are available for commercial reactors only. The scaling variable is again the electrical power output of the plant. Thus, the scaling process depends on the availability of a scaling coefficient and on the scaling variable, and is conditioned by the fact that published data on scaling are usually very limited. The proposed model could, therefore, be used to obtain a rough first estimate of how the economy of scale works. In the paragraphs that follow, scaling up and down of the AP600 type reactor will be used as an example, with the understanding that this is only an example and not an evaluation of the reactor economy itself.

II–4.1.1. Reactor data

The design and operation characteristics of the AP600 and EP1000 have been extensively published in the open literature. The data for this particular example are taken from Ref. [II–1]. The data are summarized in Table II–1.

TABLE II–1. TECHNICAL DATA USED FOR AP600 AND EP1000 [II–1]

Item	Units	AP600	EP1000
Electric power	MW(e)	600	1 000
RPV weight	t	364	468[a]
Number of fuel elements	#	145	193
Fuel length	m	3.7	3.7
Steam generator weight (each)	t	377	480
Thermal power	MW(th)	1 940	2 910
Volume of RPV vessel	m^3	144	216
Power of primary pumps (each)	MW(e)	2.24	2.24
Number of primary pumps	#	4	6
Number of steam generators	#	2	3
Fuel enrichment	%	3.55	3.55
Power density (related to fuel mass)	MW/t	29.0	32.6

TABLE II–1. TECHNICAL DATA USED FOR AP600 AND EP1000 [II–1] (cont.)

Item	Units	AP600	EP1000
Average discharge burnup	MW·d/t	40 000	50 000
Number of refuelling zones	#	3	3
Operation and maintenance costs	mills/kW·h·MW(e)	4 680	5 140[a]

[a] These values were calculated from the AP600 data, taking into account the different reactor pressure vessel (RPV) height, diameter and design pressure.

Note: 1 mill = $\$10^{-3}$.

The economic characteristics used for AP600 in the model have been taken from Ref. [II–2]. All these values are in US dollars as of 1 January 1990, and are shown in Table II–2. To compare costs calculated on other dates, the usual procedure is to introduce a correction for cost escalation, using the appropriate cost indices. To correct the nuclear power plant cost from 1991 to 2001, the nuclear plant cost adjustment factors from Ref. [II–3] will be used.

TABLE II–2. ECONOMIC DATA USED FOR AP600, IN US DOLLARS 1990 [II–2]

Item	Units	Value
Structure and improvements	million $	96.8
Reactor plant equipment	million $	193.2
Turbine plant equipment	million $	136.3
Electric plant, miscellaneous	million $	94.4
Total indirect costs	million $	162.6
Contingency	million $	135.2
Owner costs	$/kW	137
First of a kind costs (in 10 plants)	$/kW	43
Interest during construction (at 11.4% rate in dollars)	$/kW	396

To scale up the reactor without detailed cost break-down data, the order of magnitude for different parts can be evaluated using the classical cost break-down of a loop type PWR. This will not give the detailed cost data for each item, but the overall economics should not be so different from the classical gross numbers that usually constitute the reactor costs.

To obtain the cost break-down, values taken from the textbooks for conventional loop type PWRs developed in the 1980s will be used. If one uses only the relative numbers, after normalization to the AP600 values, the overall picture could be within an acceptable range. The detailed cost break-down will be taken from a standard nuclear engineering textbook [II–4]. These data, normalized to the AP600 data of Table II–2, are given in Table II–3.

The normalization has been performed keeping the published values for the main items of the AP600 and using the textbook data only to estimate the cost break-down among all smaller items included in each main item.

TABLE II–3. COST BREAK-DOWN OF A TWO LOOP PWR APPLIED TO THE AP600 CALCULATION

Item	Value from Ref. [II–4] (million $)	Normalized to AP600 (million $)
(1.1) Conventional building	16	45.6
(2.1) Containment	18	51.2
(2.2) Reactor pressure vessel	11	26.2
(2.3) Control rods	6	14.3
(2.4) Steam generator	17	40.5
(2.5) Spent fuel management	4	9.5
(2.6) Instrumentation and control	6	14.3
(2.7) Chemical and volume control system	7	16.7
(1.4) Condenser	9	21.5
(2.8) + (2.9) Others, reactor	21	50.1
(1.2) Turbogenerator	65	136.3
(1.3) Others, electrical	10	67.4
(1.5) Others, direct	4	27.0
(3.1) Special equipment	1.5	11.2
(3.2) Engineering	12.3	91.7
(3.3) Fixed indirect	0	0.0
(3.4) Conventional indirect		48.5[a]
(3.5) Nuclear indirect		11.2[a]
(3.6) Others, indirect	8	0.0

[a] These values were evaluated assuming that the indirect conventional and nuclear costs are proportional to the conventional/nuclear equipment cost ratios because the former categories are not singled out explicitly in Ref. [II–4].

Note: PWR: pressurized water reactor.

II–4.1.2. Scaling model

To scale up a reactor, a classical simple model is conventionally used, which performs an overall escalation with the electrical power output [II–5]. This model assumes that the adequate value to scale up different cost items is electric output only. It may be correct if the main design features are not changed, such as when a three loop PWR is scaled up to a four loop PWR, but this will not be adequate when certain systems and design characteristics are changed. A more detailed engineering model for scaling of costs is proposed in Ref. [II–6].

To estimate the overall cost, a top-down approach [II–3] will be used, but applied only to those main design features that are relevant to design simplification. In this way, the cost break-down items of Table II–3 will be scaled with a minimum dataset available in the open literature for almost any advanced reactor type.

The above mentioned minimum dataset is given in Table II–4 by taking into account trade-offs involved in design simplification. As can be seen from the table, this set includes a very small number of scaling variables, either available for nuclear reactors of many types, or so simple that they could easily be evaluated with a relatively small uncertainty. Then, the next step is to select proper scaling variables for the items in Table II–3 among the available scaling variables in Table II–4.

Using these variables, a simplified scaling model for the overall economics of a PWR can be built, by relating each item in Table II–3 to the variables in Table II–4, with proper scaling coefficients obtained from Refs [II–3, II–5, II–6].

The data for such a model can be seen in Table VII–5. For the items for which scaling data were not available in the literature, the scaling coefficients were derived from the present model. The first such item was the cost of the containment. It was assumed that the scaling variable is the weight of the steam generators plus the weight of the RPV, as these are the measures of the primary coolant system size.

TABLE II–4. MINIMUM SET OF VARIABLES TO PERFORM A SIMPLE SCALING COST ASSESSMENT

Scaling variable	Symbol	Value for AP600 from Ref. [II–1]	Value for EP1000 from Ref. [II–1]
Electric power (MW(e))	Pe	600	1 000
RPV weight (t)	RPV_w	260	335
Number of fuel assemblies	EECC	108	144
Core length (m)	L_n	4.3	4.3
Guard vessel weight (t)	GV_w	527	1 008
Electrical efficiency (%)	η	30.9	34.4
Primary system volume (m^3)	Vps	96	144
Total primary pump power (MW(e))	PP	8.96	13.44
Fuel enrichment (%)	ε	3.55	3.55
Power density of fuel (MW/t)	δ_{th}	29.0	32.6
Average fuel burnup (MW·d/t)	Q	44 000	55 000
Number of refuelling zones	Nz	3	3
Load factor (%)	Lf	80	80
Operation and maintenance cost (mills/kW·h·MW(e))	O&M	4 680	6 014[a]

[a] The value was estimated by scaling the reactor pressure vessel (RPV) weight because it is not available in Ref. [II–1].

Note: 1 mill = $\$10^{-3}$.

The coefficient used was typical for metal vessels [II–6]. For the other four such items, a simple calculation of the cost assumed to be proportional to a very simple cost variable (e.g. for the RPV, the cost was assumed to be proportional to the weight) was applied. Such an approximation may be valid within a reasonably small range around the reference value, and it can be used to determine first order cost trends.

To calculate the final LUEC cost using Eq. (II–3), the discount rate, the amortization time, the load factor and the interest during construction need to be defined, as well as the PWR fuel cycle cost structure. To calculate the fuel costs $(\$/kg)_{FE}$, a simplified model from the International Project on Innovative Nuclear Reactors and Fuel Cycles manual has been used [II–7]. The value of the discount rate was taken to be 6.1% (constant), corresponding to the published data on AP600 [II–1]. The interest during construction was estimated in the assumption of a single delay; such an approximation produces only a few per cent discrepancy with the detailed published data [II–7]. The fuel cycle cost data used in the calculation for the reference case correspond to Ref. [II–8], which is a well known published data source giving values very close to some internal values of Ref. [II–9], and very close to the published generation cost break-down of Ref. [II–1]. These values, with an 80% load factor and a 30 year amortization life [II–1], are given in Table II–6.

TABLE II–5. BASIC DATA TO PERFORM LUEC CALCULATIONS USING EQS (II–3) AND (II–6)

Item	Variable to scale up the cost item	Scaling coefficient	Ref. for scaling coefficient
Conventional building	Pe	0.5	[II–5]
Containment	$RPV_w + GV_w$	0.667	This model
RPV	RPV_w	1	This model
Control rods	$EECC \times L_n$	1	This model
Steam generator	GV_w	1	This model
Spent fuel management	$(Pe/\eta)/Q$	1	This model
Instrumentation and control	Pe/η	0.6	[II–3]
Chemical and volume control system	Vps	0.667	[II–6]
Condenser	Pe/η	0.72	[II–6]
Others, reactor	Vps	0.6	[II–3]
Turbogenerator	Pe	0.8	[II–5]
Others, electrical	Pe	0.6	[II–5]
Others, direct	Vps	0.3	[II–5]
Special equipment	Pe/η	0.4	[II–5]
Engineering	Pe	0.2	[II–5]
Fixed indirect	n.a.	0	n.a.
Conventional, indirect	Pe	0.75	[II–5]
Nuclear, indirect	RPV_w	0.5	[II–5]
Others, indirect	Pe	0.4	[II–5]

Note: LUEC: levelized unit energy cost; n.a.: not applicable; RPV: reactor pressure vessel.

With all of the above mentioned data, the LUEC for the AP600 can be easily calculated using Eq. (II–3); then, this cost can be compared with published data. The results of the calculation together with the published data [II–1, II–9] are shown in Table II–7. There is excellent agreement between all results.

TABLE II–6. ADDITIONAL DATA REQUIRED FOR LUEC CALCULATION

Item	Time (a)	Base value	Units
Uranium purchase	1.5	50	\$/kg U
Conversion	1	8	\$/kg U
Enrichment	0.75	110	\$/SWU
Fabrication	0.5	275	\$/kg U
Real discount rate		6.1	%/a
Load factor		80	%
Amortization time		30	a

Note: LUEC: levelized unit energy cost. SWU: separative work unit.

TABLE II–7. COMPARISON OF LUEC CALCULATIONS FOR AP600 VERSUS PUBLISHED DATA

Item	Calculated	Ref. [II–1]	Units
Amortization	28.4	28	mills/kW·h
Operation and maintenance	7.8	8	mills/kW·h
Fuel	7.1	7	mills/kW·h
Total	43.3	43	mills/kW·h

Note: LUEC: levelized unit energy cost; 1 mill = $\$10^{-3}$.

The last step to building a scaling model is to obtain the scaling of Eq. (II–10) for each of the scaling variables of Table II–4. For the case considered, it can be carried out easily because, over the last 10 years, the AP600 design concept has been studied in three and four loop configurations, so that the parameters for these configurations are available in the open literature.

The initially considered scaled up versions with three and four loops were called SPWR 3 and SPWR 4, respectively [II–10]. Later activities were focused on a three loop reactor, essentially a scaled up version of the AP600, called EP1000 [II–1], and usually presented as a natural evolution up rated version suitable for Europe [II–11].

Thus, the main variables of the EP1000 (or a three loop AP600) are available in the open literature [II–1], and they were included in Table II–4. A very simple scaling function could be defined by the two values of Table II–4. To make a practical calculation according to Eq. (II–8), a classical scaling approach was applied with the two values available at two electrical output levels (Table II–4):

$$V_x = V_x^0 (\mathrm{Pe})^{\gamma_x} \tag{II–11}$$

Each coefficient can then be calculated as follows:

$$V_x^0 = V_x^{\mathrm{AP600}} \text{ and } \gamma_x = \left[\log\left(V_x^{\mathrm{EP1000}}\right) - \log\left(V_x^{\mathrm{AP600}}\right)\right] \Big/ \log(1000/600)$$

The quality of this approach was checked using the data published for the four loop PWR version [II–10], with excellent agreement observed.

II–4.1.3. AP600 scaling up results and simplification assessment

Using Eq. (II–11) to scale the variables with the data of Table II–4, and calculating the cost items of Eq. (II–7) with the scaling coefficients of Table II–5 and the reference values of Tables II–3 and II–4, the overnight cost at different power levels can be calculated using Eq. (II–9). For simple scaling up, there is no simplification or design change assumed, so all the simplification coefficients $K_{i,j}^{d_k}$ are set equal to one.

Figure II–5 shows the data of Table II–8 as a set of curves.

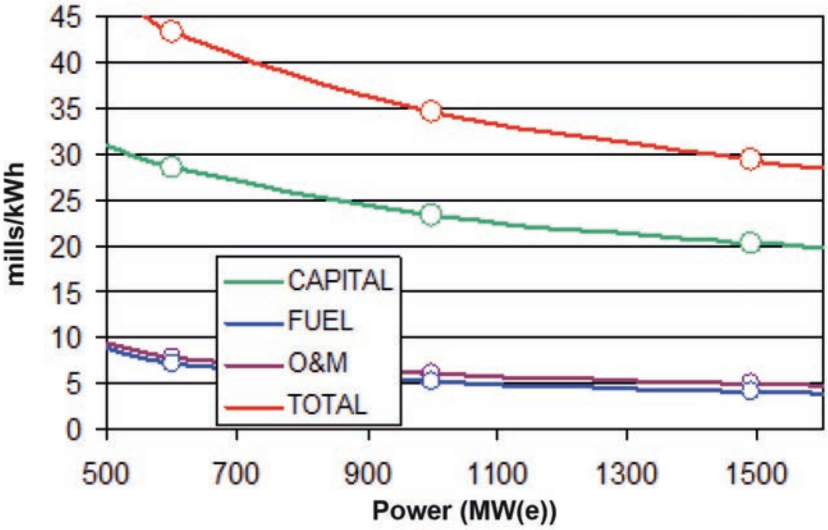

FIG. II–5. Generation cost of scaled up AP600 designs. O&M: operation and maintenance.

TABLE II–8. LUEC CALCULATIONS FOR SCALED UP AP600

Item	Calculated AP600 with two loops	Calculated with three loops	Calculated with four loops	Units
Power	600	1000	1500	MW(e)
Overnight	1550	1271	1100	\$/kW(e)
Amortization	28.4	23.3	20.2	mills/kW·h
Operation and maintenance	7.8	6.0	4.9	mills/kW·h
Fuel	7.1	5.2	4.2	mills/kW·h
Total	43.3	34.5	29.3	mills/kW·h

Note: LUEC: levelized unit energy cost; 1 mill = $\$10^{-3}$.

The value of the generation cost of a three loop reactor could be compared with the corresponding value for the twin unit AP600. For such a comparison, values for the twin unit AP600 at the same discount rate and plant lifetime were taken [II–9]. In this reference, the total LUEC is equal to 3.9 mills/kW·h (1 mill = $\$10^{-3}$). A comparison between the AP600 type single unit plant at different power levels (Fig. II–5) and the twin unit value is shown in Fig. II–6.

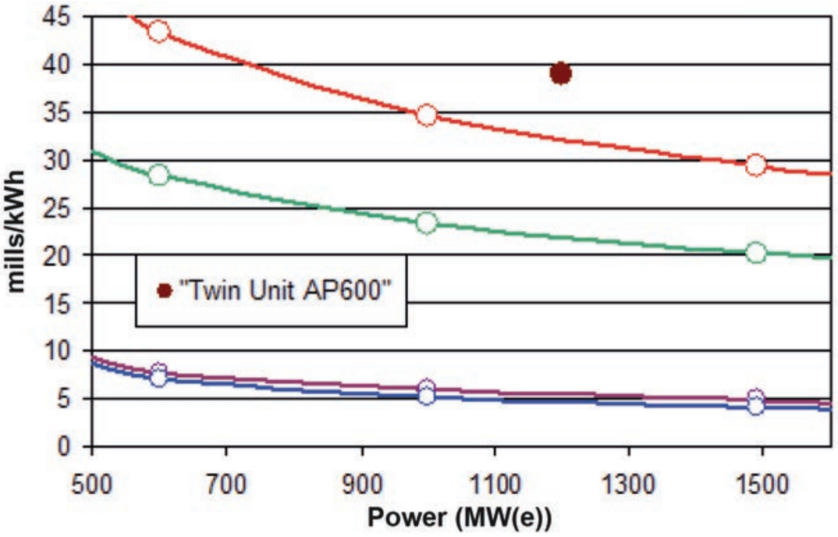

FIG. II–6. AP600 design concept scaled up with three and four loops in the primary system.

This presented comparison is in good agreement with the published results of economic comparison between the uprated AP600 and the AP600 twin unit, if the corresponding values are corrected by different discount rates and fuel cycle costs used [II–12]. The qualitative conclusion is the same — the twin unit, although having a higher cumulative output, loses to the up scaled three loop design, although it does improve against the reference single unit design [II–11].

II–4.2. Example of loop type PWRs with passive systems and improved economic targets

It is obvious that a higher power output could produce a significant cost reduction.

The cost break-down of a typical PWR (Table II–3) shows that the containment and the conventional buildings, together with the RPV and steam generators, are, altogether, the more expensive items of the plant (the reactor and other items are very expensive too, but include tens of various systems). The conventional and electrical items are essentially similar in any PWR employing a Rankine cycle, and their design cannot be easily changed within the limits of light water reactor technology (a Brayton energy conversion cycle can be simpler and more compact than a Rankine cycle, but it cannot be applied efficiently at ~350°C core outlet coolant temperatures typical of light water reactors).

Then, any design change that could increase the power output, or could ensure savings on the components made of steel and/or the reactor building, will produce a cheaper plant, if there are no other systems that are more expensive as a consequence of that design change.

The two approaches mentioned above could be tried in application to a PWR system. One approach is to increase the power output by increasing the power density. Another approach is to increase the steam generator size in order to achieve a higher power output with the associated reduction in specific costs of the primary pressure boundary and the containment.

II–4.2.1. Increased power density and improved steam generator design

Increased power density could be defined as a design change d_{pd} that is greater than one when the power density is increased. For example, it could be the ratio of a power density to a reference value of the power density.

Then, the overall improvement from a core power density increase could be measured by the corresponding impact on the RPV weight, in the number of fuel elements, in the volume of the primary system and in the uranium core load, via a simple proportional reduction or increase, as shown in Table II–9 for those variables that are close to proportional in their response to core power density changes or are proportional to the square root of such changes, which is typical of the primary system volume and the weight of steel in the RPV.

TABLE II–9. CHANGES IN THE VARIABLES RESULTING FROM CHANGES IN MAJOR PLANT PARAMETERS

Variable	Original value	Modified value
Reactor pressure vessel weight	RPV_w	$RPV_w/d_{pd}^{1/2}$
Number of fuel elements	EECC	$EECC/d_{pd}$
Primary system volume	Vps	$Vps/d_{pd}^{1/2}$
Power density	δ_{th}	$\delta_{th} \times d_{pd}$
Steam generator weight	GV_w	GV_w/d_{sg}
Electrical power	Pe	$Pe \times d_{po}$

An alternative steam generator design can be adapted to improve plant performance. This alternative design may enable the steam generator to accommodate a higher reactor power without adding an extra loop to the reactor coolant system. In a similar manner, the improvement through a design change d_{sg} can be evaluated following the break-down given in Table II–9.

A plot of LUEC for these two design changes (interpolation was used to draw this plot) is shown in Fig. II–7. This figure shows that if the power output could be significantly increased and the specific steam generator weight could be decreased, then the LUEC can be decreased by ~2 mills/kW·h.

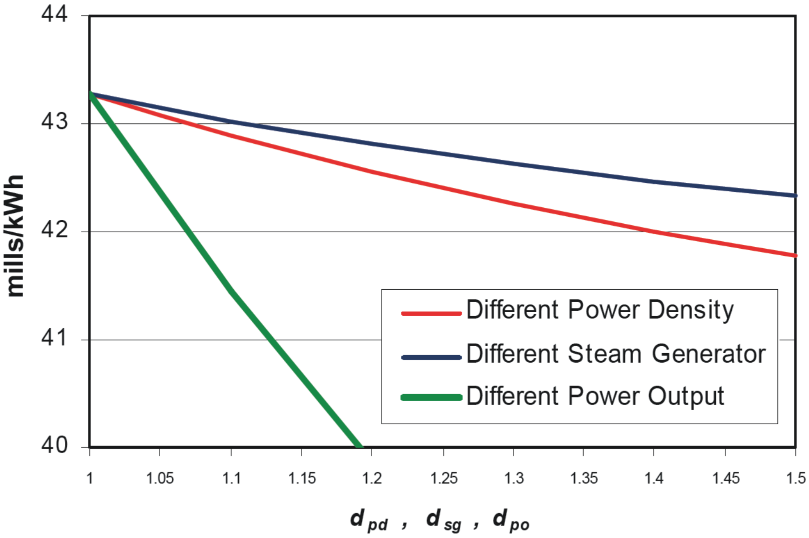

FIG. II–7. Total levelized unit energy cost (LUEC) for the AP600 concept with three design changes d_{pd}, d_{sg} and d_{po}. AP1000 as a simplified EP1000.

A third design change could be just to increase the power output, which is a rough approximation of classical power up rate. Increasing the power output would produce exactly the same savings as shown in Fig. II–5. However, the power up rate could also be viewed as a design change to study the sensitivity of LUEC in a reactor of a given type. The design change d_{po} can then be defined as an increased power output divided by the reference 600 MW(e) value. The impact of such a change on LUEC is also shown in Fig. II–7.

The slope of the power up rate curve is much higher than that of the other considered design changes, which tackles the impact of the two most costly components of the primary system. It should be noted that the power up rate changes the specific costs of the primary system, but also reduces the specific costs of all of the auxiliary and conventional systems. This is why there is a never ending tendency for light water reactors to try to achieve a higher power output for a given design.

Considering that the AP600 type reactor with close to 1000 MW(e) power output could achieve an LUEC close to 34 mills/kW·h, an additional increase of the power density and use of the higher output steam generators could result in a 32 mills/kW·h LUEC design. In the latter case, the containment and the primary system will be only marginally larger than those of the original two loop 1000 MW(e) design, resulting in the substantial savings indicated.

Following EP1000, AP1000 has been presented [II–11] as a logical next step in the design evolution of a loop type PWR with passive systems at a power level higher than 600 MW(e). The AP1000 has a higher power output than the EP1000; it is around 1117 MW(e). Compared to EP1000, the AP1000 reactor has a higher power density core. With the same RPV diameter and a slightly larger number of fuel elements, AP1000 incorporates only minor changes in the RPV length. Therefore, this design change could be directly linked to d_{pd}, as introduced previously.

The higher thermal power output does not require a third loop; instead, steam generators of the alternative design of a capacity higher than that in the AP600 are used. Such a design change could be directly linked to d_{sg}, as introduced previously.

In addition, the power output has been significantly increased from 600 to 1117 MW(e). This design change could be directly linked to the previous d_{po}.

As this is a specific design study, and not a generic study of the tendencies in savings, the new design could be modelled by changing the design variable d_{po} coupled with the introduction of the proper *K* factors for d_{pd} and d_{sg}, $K_{i,j}^{d_{\mathrm{pd}}}$ and $K_{i,j}^{d_{\mathrm{sg}}}$.

The *K* factors from Eq. (II–9) have been defined for different cost items by keeping the item scaling variables to the sizes of the AP600 reactor, in particular, for the steam generators and the RPV [II–13], and then by comparing them to the scaled values at the power output corresponding to that of AP1000 (1117 MW(e)). Additional saving factors can be evaluated for the costs of the containment and the chemical and volume control system because the containment has the same diameter as in AP600 and only its height was increased on transition to AP1000. There is a relevant reduction in the specific auxiliary system costs owing to the reduction in the number of loops compared to EP1000. The indicated *K* factors are summarized in Table II–10.

There are other changes that could be modelled as design changes of some reactor variables and not directly as cost items, such as the number of fuel elements, the core length, the electrical efficiency, the volume of the primary system, the power density, the fuel burnup and the fuel enrichment. The design change factors for these variables are given in Table II–10.

Using these data, and the project and external data used for the AP600, LUEC values, as shown in Table II–11, can be obtained and compared to the data from Table II–8 calculated on the same basis.

The results obtained are in good agreement with the values published previously, if we note the uncertainties introduced by the approximations of the method and data used. For example, the model gives $1113/kW(e) for the AP1000 overnight investment, while the corresponding values published in Refs [II–12, II–14] are $1070/kW(e) and $1200/kW(e), respectively. The reference year used in Ref. [II–12] is 1990, but Ref. [II–14] does not specify any reference time for the performed evaluation. Altogether, the results obtained with the proposed model could be rated as an acceptable first order evaluation of the AP1000 LUEC based on the scaling model of AP600.

From Table II–11, it can be seen that the simplification approach used for AP1000 (AP1000 is a two loop simplified version of the three loop EP1000) yields a significant saving, very close to the saving from the transition to a 1500 MW(e) PWR.

Looking at Fig. II–6, it can be noted that there is a large saving when the power output is increased from 600 to 1100 MW(e), but the saving for a power increase from 1100 to 1500 MW(e) appears to be smaller.

TABLE II–10. *K* FACTORS AND DESIGN CHANGE VARIABLES OBTAINED BY COMPARING SCALED UP AP600 AND AP1000 DATA

K factors

Item	*K*	Value
Containment	$K_{2,1}^{d_{\text{AP1000}}}$	0.73
Reactor pressure vessel	$K_{2,2}^{d_{\text{AP1000}}}$	0.76
Steam generator	$K_{2,4}^{d_{\text{AP1000}}}$	0.80
Chemical and volume control system	$K_{2,7}^{d_{\text{AP1000}}}$	0.73

Design change variables

Variable changed	Symbol	Value
Number of fuel elements EECC	$\text{EECC}/d_{\text{pd}}$	$d_{\text{pd}} = 1.13$
Core length L_{n}	$L_{\text{n}} \times d_{\text{fl}}$	$d_{\text{fl}} = 1.15$
Electrical efficiency η	$\eta \times d_{\text{bop}}$	$d_{\text{bop}} = 0.93$
Primary system volume $V\text{ps}$	$V\text{ps} \times d_{V\text{ps}}$	$d_{V\text{ps}} = 0.63$
Enrichment ε	$\varepsilon \times d_{\text{e}}$	$d_{\text{e}} = 1.25$
Power density δ_{th}	$\delta_{\text{th}} \times d_{\text{pd}}$	$d_{\text{pd}} = 1.13$
Average fuel burnup Q	$Q \times d_{\text{q}}$	$d_{\text{q}} = 1.15$

TABLE II–11. COMPARISON OF LUEC CALCULATION AMONG AP600, EP1000, AP1000 AND FOUR LOOP PWRs

Item	Calculated AP600 with two loops	Calculated EP1000 with three loops	Calculated PWR with four loops	Calculated AP1000 with two loops	Units
Power	600	1000	1500	1117	MW(e)
Overnight	1550	1271	1100	1113	\$/kW(e)
Amortization	28.4	23.3	20.2	20.4	mills/kW·h
O&M	7.8	6.0	4.9	4.19	mills/kW·h
Fuel	7.1	5.2	4.2	5.7	mills/kW·h
Total	43.3	34.5	29.3	30.3	mills/kW·h

Note: LUEC: levelized unit electricity cost; O&M: operation and maintenance; PWR: pressurized water reactor; 1 mill = $\$10^{-3}$.

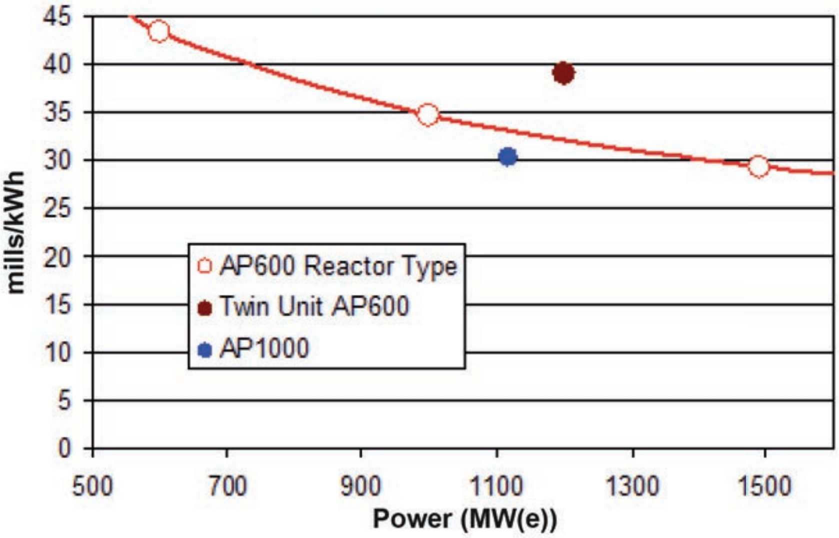

FIG. II–8. Levelized unit energy cost of the AP600 type concept scaled up to three and four loop primary systems.

II–4.3. Example of a reactor based on railroad transportable modules

The previous examples covered a number of different design changes, but only for a PWR reactor developed in one country. Economic comparisons between reactors of even the same type but developed in different countries may not be simple, especially if published economic data are involved, because of differences in the economic systems of the countries.

Even in Organisation for Economic Co-operation and Development countries, a large spread of similar data on costs and construction schedules of loop type PWRs is observed, even when these data are attributed to the same year [II–15]. A similar situation is observed for economic data of combined cycle gas turbine plants [II–15]. From the analysis of all these data, it follows that variations of the purchasing power of national currencies between countries are, by themselves, not sufficient to introduce adequate corrections to the comparative economic assessments of nuclear reactors developed in different countries.

Thus, the applicability of the proposed method to assessments involving transitions from one technology to another should be examined with great care. However, the order of magnitude of cost changes in generic studies may remain valid, at least, for relative comparisons between different alternatives under the same external conditions.

As the proposed method (model) aims to be applicable to reactors of different types, the next example will be focused on reactors that are technologically very different from a loop type PWR, such as a small, long life, sodium cooled reactor with a gas turbine power circuit and no intermediate heat transport system. The results of the simplification assessment in this case may, of course, be considered only as very general and not detailed enough for engineering purposes.

II–4.3.1. The BN-GT 300 design concept

Reference [II–16] presents the concept of a small sodium cooled reactor of 300 MW(e) with a Brayton cycle gas turbine power conversion system. The plant is divided into modules that are transportable by train. This design concept is named BN-GT 300, and was developed by the Institute of Physics and Power Engineering (Russian Federation). To assess the LUEC of the BN-GT 300, the proposed method would treat three groups of design changes, reflecting certain groups of design rules extensively applied in the design concept. The values used in each of the groups are given in Table II–12 based on light water reactor basic data at 300 MW(e).

The first group of changes covers major changes related to the transition from a PWR to a sodium cooled reactor. The core now uses fuel with relatively higher enrichment, the core has a lower power density, and a cassette type refuelling of the core (one at a time whole core reload) is applied. The efficiency is higher and the weight of the primary vessel is much smaller.

TABLE II–12. MINIMUM SET OF VARIABLES TO PERFORM A SIMPLE SCALING COST ASSESSMENT OF THE BN-GT 300

Scaling variable	Design change	Value for BN-GT 300 [II–16]	Value for a PWR with passive systems at 300 MW(e)
First group of changes: sodium cooled reactor with cassette refuelling			
Electric power (MW(e))		300	300
RPV weight (t)	$\text{RPV}_{\text{w}} \times d_{\text{RPV}}$	86[a]	259
Number of fuel assemblies		98[b]	98
Core length (m)	$L_{\text{n}} \times d_{\text{ln}}$	1.1	3.7
Guard vessel weight (t)		313[b]	313
Electrical efficiency (%)	$\eta \times d_{\text{n}}$	41	27
Primary system volume (m^3)		83[b]	83
Total primary pump power (MW(e))		5.2[b]	5.2
Fuel enrichment (%)	$\varepsilon \times d_{\text{e}}$	17	3.55
Power density of fuel (MW/t)	$\delta_{\text{th}} \times d\delta$	26	45
Average fuel burnup (MW·d/t)	$Q \times d\delta$	46 000	29 550
Number of refuelling zones	$\text{Nz} \times d_{\text{Nz}}$	1	3
Load factor (%)		80	80
Operation and maintenance cost (mills/kW·h·MW(e))		3 329[b]	3 329
Second group of changes: Brayton energy conversion system			
Turbogroup technology		$K_{1,2}^{d_{\text{BNGT-2}}}$	1/3[c]
Others, reactor technology		$K_{1,5}^{d_{\text{BNGT-2}}}$	1/3[c]
Auxiliary systems, technology		$K_{2,7}^{d_{\text{BNGT-2}}}$	1/3[c]
Heat sink technology		$K_{1,4}^{d_{\text{BNGT-2}}}$	1/3[c]
Third group of changes: railway transportable modular system			
Conventional buildings		$K_{1,1}^{d_{\text{BNGT-3}}}$	1/3
Containment		$K_{2,1}^{d_{\text{BNGT-3}}}$	1/3

TABLE II–12. MINIMUM SET OF VARIABLES TO PERFORM A SIMPLE SCALING COST ASSESSMENT OF THE BN-GT 300 (cont.)

Scaling variable	Design change	Value for BN-GT 300 [II–16]	Value for a PWR with passive systems at 300 MW(e)
Construction facilities		$K_{9,1}^{d_{\text{BNGT-3}}}$	1/3
Construction time $T_{\text{effectiveCt}}$		$T_{\text{effectiveCt}} \times d_{\text{M}}$	1/4

[a] The value was estimated based on the assumption that the reactor pressure vessel (RPV) size is very similar to a pressurized water reactor (PWR) at 300 MW(e), but at one third of the primary pressure.

[b] The variables were assumed to be similar to those of a PWR.

[c] The variables were multiplied by 1/3 because this is a typical cost ratio between a Brayton engine and a Rankine engine (and associated systems). Values of the third group have been estimated only in a generic way, to study the sensitivity for such a design approach.

Note: 1 mill = $\$10^{-3}$.

The second group of changes includes the main changes related to the use of a gas turbine Brayton cycle (instead of a Rankine steam cycle), resulting in a significantly cheaper turbogroup and auxiliary systems compared to steam–water systems. The new values were evaluated to be one third of the respective PWR values because this is a typical cost ratio for Brayton cycle and Rankine cycle engines of the same power rating.

The third group of changes brings together all major changes related to the replacement of classical buildings to railway transportable modules and employment of a very fast and simple construction technique. At present, there is no commercial experience with such an approach in nuclear technology; thus, the simplification coefficients have been estimated only as parameters to analyse LUEC sensitivity to this type of design approach.

The analysis of the impact of design changes was applied step by step, to visualize the order of magnitude of the changes that could be produced by the indicated three groups of design changes.

II–4.3.2. Results for application of the three groups of design changes

The results of step by step application of the three groups of design changes, in comparison with the reference PWR of 300 MW(e) scaled down from the AP600 type PWR discussed earlier in this annex, are shown in Table II–13 and Fig. II–9.

From Table II–13 and Fig. II–9, it can easily be seen that a PWR with a power output of 300 MW(e) represents a relatively expensive initial point, with an LUEC nearly 50% more expensive than that for a 600 MW(e) AP600 type reactor, from which a smaller PWR has been scaled down.

Use of sodium as a reactor coolant (first group of design changes in Table II–12) reduces the overnight costs slightly (~10% in amortization costs), but the fuel cycle costs become much more expensive owing to substantially higher fuel enrichment and relatively low fuel burnup for the enrichment grade. Therefore, the total LUEC is equal to 9 mills/kW·h, which is more expensive than for the reference case.

Use of the Brayton cycle (second group of design changes) reduces the investment, achieving reactor overnight costs similar to those of AP600, but very expensive fuel cycle costs result in a generation cost that is still similar to that of a reference 300 MW(e) PWR.

The use of a modular construction technique (third group of design changes) substantially reduces the cost of civil works, yielding a significant reduction in the overnight costs (bringing them close to the AP1000 reactor). The shorter construction time reduces the amortization cost substantially. Altogether, the evaluated LUEC for the BN-GT 300 appears to be between the 300 and 600 MW(e) PWR LUEC values.

Published data on costs for the BN-GT 300 are sparse; actually, only the fabrication cost value of \$593/kW(e) could be found in Ref. [II–15]. One can assume that Ref. [II–15] makes no extensive use of the first of a kind (FOAK) and contingency cost factors, such as were taken into account in the detailed AP600 reference value; in that case, the calculated overnight cost of the BN-GT 300 would be reduced from \$1256/kW(e) to \$923/kW(e).

TABLE II–13. COMPARISON OF LUEC CALCULATIONS FOR A 300 MW(e) PWR, A 600 MW(e) PWR AND A BN-GT 300 SODIUM COOLED SMALL REACTOR

Item	Calculated PWR	Scaled down PWR	Design group 1	Design group 2	Design group 3	Units
Power	600	300	300	300	300	MW(e)
Total investment	1850	1249	1292	1021	798	million $
Overnight cost	1550	2092	1913	1431	1256	$/kW(e)
Amortization cost	28.4	38.7	35.4	26.5	19.2	mills/kW·h
O&M cost	7.8	15.6	15.6	15.6	15.6	mills/kW·h
Fuel cost	7.1	10.6	22.9	22.9	22.9	mills/kW·h
Generation cost	43.3	64.9	73.9	65.0	57.6	mills/kW·h

Note: LUEC: levelized unit energy cost; O&M: operation and maintenance; PWR: pressurized water reactor; 1 mill = $\$10^{-3}$.

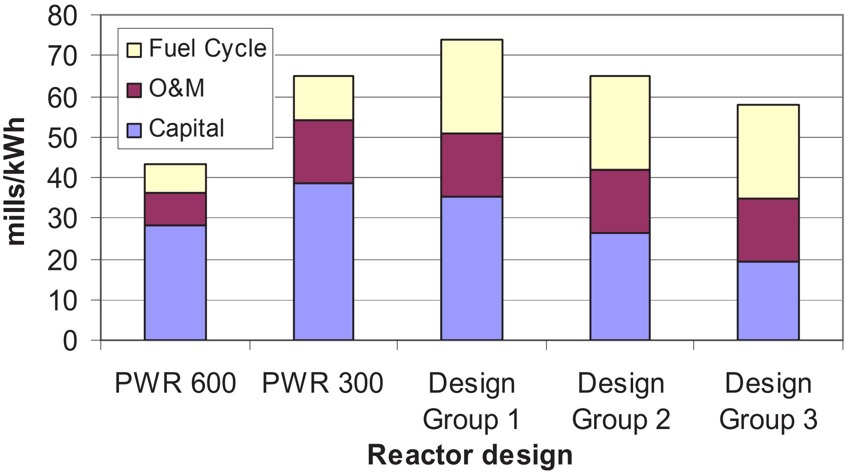

FIG. II–9. Levelized unit energy cost components for the AP600 type concept, scaled down 300 MW(e) pressurized water reactor (PWR) and BN-GT 300 concept scaled from a 300 MW(e) PWR. O&M: operation and maintenance.

It is not indicated clearly whether the indirect costs were included in the number given in Ref. [II–15], and the scaling model (in our case, based on PWR technology) might be very different for reactors of this new type. However, there would be many new elements in the indirect cost calculation for a BN-GT 300 type reactor. As it is very different from present day technology, there would also be many uncertainties related to each cost item. For example, commercial experience shows low indirect costs for Brayton engines; however, for a sodium cooled primary system, the cost could turn out to be similar or even more expensive than that in a PWR. There is no experience supporting the calculations of the indirect costs of buildings replaced by railway cars; there are many issues here related to their engineering, interaction, commissioning, safety issues, etc. In other words, in view of possible uncertainties, the indirect costs for the BN-GT 300 could be much lower or higher compared with a PWR scaled down to the same power.

Nevertheless, the example presented here shows how the discriminative power of the method is sufficient to study the separate effects in LUEC resulting from different groups of design changes, economic trade-off between the introduced changes and those necessitated by such an introduction, as well as bottlenecks and key uncertainties in the overall economics of a new plant.

For the case considered here, the analysis performed clearly points to many of the advantages that could be expected from this advanced design, compared to a more classical PWR technology reactor (at the same contingency factor). However, it is also clear that with the reduced core power density and 17% of the enrichment, the first core would be very expensive compared to a PWR core. In addition to this, the relatively small fuel burnup of 46 000 MW·d/t appears to be low for the high grade of enrichment used.

The proposed method offers a discriminative power that could be effectively used in the early design stages of a new plant in order to improve the economy of the design concept. Thus, for the BN-GT 300, any design changes that would reduce the fuel enrichment and increase the core power density will strongly decrease the LUEC. However, the design changes targeted at the power up rate should not result in a loss of the advantages related to a demountable, modular design, packable in railway cars, because this will reduce the savings related to the third group of design changes shown in Table II–12.

For PWR type reactors, a good example of the power uprating is provided by scaling up from AP600 to AP1000 [II–14]. The design changes implemented for such an up rating include only a slightly longer containment, but of the same diameter, which became possible because the RPV diameter was retained, and the larger capacity steam generators were arranged in a similar reactor cavity module.

II–4.4. Example of a high temperature gas cooled reactor with tri-isotropic fuel

At present, several designs of high temperature gas cooled reactors (HTGRs) are being considered around the world, and all of them employ tri-isotropic (TRISO) fuel elements. Some of the designs employ a direct Brayton cycle gas turbine power conversion system [II–17]. Most HTGR design concepts have historically evolved from the original design concept of General Atomics [II–18].

The HTGR concept is very different from light water reactors; its attractive features include a very simple primary system and power conversion system compared to conventional PWRs and boiling water reactors.

II–4.4.1. HTGR design concept

The HTGRs being considered employ different designs of fuel (prismatic block or pebble bed) and different gas turbine configurations (horizontal or vertical, single shaft or multiple shaft) [II–17], but have several common design features, which are the same basic type of fuel (TRISO coated particles) and the simple decay heat removal system, providing for passive removal of the decay heat to the outside of the reactor vessel, relying on heat conduction, convection and radiation in all media, without any special provisions for natural circulation inside the reactor vessel.

The proposed method combines two types of scaling variable: those that are defined by the simplification approach applied to a reactor system, and those that arise from changing component sizes, i.e. defined by several variables such as power density and volume of the primary system.

Usually, the approach is to achieve a competitive design by using the advantage of very high core outlet temperatures allowing attainment of energy conversion efficiencies between 41 and 48%. However, all TRISO fuelled reactors have a relatively high core power density because the graphite:uranium ratio is much higher than the hydrogen:uranium ratio in water cooled reactors. In addition, the TRISO fuel size is very small compared to the neutron mean free path in graphite/uranium systems; thus, the reactivity savings, typical of the heterogeneous fuel of water cooled reactors, are lost, and the overall fuel enrichment needs to be much higher in order to achieve criticality and an acceptable enrichment:fuel burnup ratio.

For the reasons mentioned above, the scaling variables of the model would be significantly changed by the different physical sizes of the HTGR components compared to in a light water reactor. As, at present, there is a large dispersion between the variables of different HTGR designs, the average values will be taken, corresponding to the GA-HTGR, pebble bed modular reactor (PBMR) and GTHTR 300 described in Ref. [II–17]. Maximum and minimum values will also be considered to analyse possible uncertainty ranges. Table II–14 gives all these values in comparison with the values averaged between AP600 and AP1000 PWRs.

As can be seen from Table II–14, the size of the primary system in HTGRs is much larger than in PWRs (up to eight times larger). In addition to this, the fuel enrichment in HTGRs is two to five times higher than in PWRs.

TABLE II–14. COMPARISON OF SCALING VARIABLES AMONG HTGRs (GA-HTGR, PBMR, GTHTR 300) AP600 AND AP1000

Item	Average value AP600–AP1000	Average value HTGR	Maximum value HTGR	Minimum value HTGR	Units
RPV weight/power	0.6	4.6	4.8	4.4	t/MW(e)
Efficiency	31.8	45	48	41	%
Power density (inverse)	0.09	0.02	0.026	0.016	t U/MW(e)
Fuel burnup	50 000	107 000	121 000	80 000	MW·d/t U
Primary pressure	15.5	7.7	9.0	7.0	MPa
Core length	4.0	9.0	11.0	8.0	m
Fuel enrichment by ^{235}U	4.2	14.0	19.8	8	%

Note: HTGR: high temperature gas cooled reactor; PBMR: pebble bed modular reactor; RPV: reactor pressure vessel.

The thermal-dynamic cycle efficiency of HTGRs is 40% higher than that of PWRs; however, the reactor vessel has an approximately 800% larger weight. Thus, the overall economy of HTGRs would strongly depend on achieving much simpler and cheaper reactor systems, to compensate for the oversized reactor components. Without the data on system weight, and the number of valves or mass flow rate in the systems, the *K* factors will be estimated optimistically low, to give an optimistic view of HTGR economic performance compared to PWR reactors. The values of the *K* factors used are shown in Table II–15.

TABLE II–15. *K* FACTORS ESTIMATED AS OPTIMISTIC LOWER LIMITS OF TRISO-GCR TECHNOLOGY

K factors		
Item	*K*	Value
Containment	$K_{2,1}^{d_{\mathrm{TRISO}}}$	0.1
Turbogenerator	$K_{1,2}^{d_{\mathrm{TRISO}}}$	0.3
Steam generator	$K_{2,4}^{d_{\mathrm{TRISO}}}$	2
Chemical and volume control system	$K_{2,7}^{d_{\mathrm{TRISO}}}$	0.1
Others, reactor	$K_{2,8}^{d_{\mathrm{TRISO}}}$	0.1
Spent fuel management	$K_{2,5}^{d_{\mathrm{TRISO}}}$	2
Conventional building	$K_{1,1}^{d_{\mathrm{TRISO}}}$	0.1
Design change variable		
Construction time $T_{\mathrm{effectiveCt}}$	$T_{\mathrm{effectiveCt}} \times d_{\mathrm{M}}$	0.8

Note: TRISO-GCR: tri-isotropic gas cooled reactor.

The values for the containment and conventional building were optimistically assumed to be 0.1 of the corresponding values for a PWR. The assumption was that containment requirements are less strict in the HTGR case, while the conventional building of a Brayton cycle turbomachine is known to be much simpler than a steam turbine building, with only a fraction of the auxiliary systems required for a PWR.

Other reactor systems (safety systems and auxiliary systems), and the chemical and volume control system, were also evaluated as 0.1 of the values for a PWR because, although still required, the systems could be substantially more simple than in a PWR.

The construction time has been evaluated at 0.8 of the construction time of the AP600 reactor because the AP600 also assumes a very advanced modular construction technology, and there is a trade-off between the much simpler reactor systems and the much larger primary system size.

The steam generator costs have been evaluated as twice as high as a PWR; de facto, in the economic analysis of HTGRs, steam generators are replaced by heat recuperators, which are gas–gas heat exchangers offering a heat transfer coefficient less than one half of the PWR steam generator value (thermal power of PWR steam generators is larger, but for this analysis, we assumed the same power for both HTGR and PWR heat exchangers).

The HTGR spent fuel management was assumed to be twice as expensive as that of a PWR because the uranium quantity to be managed in HTGRs nearly doubles (four times the lower uranium density, but twice as high fuel burnup).

The HTGR O&M costs have been evaluated at 20% of the corresponding PWR costs, assuming that O&M costs in HTGRs would have the same scope as those of fossil fuelled gas turbines.

Figure II–10 shows the LUEC for HTGR type reactors (TRISO-GT) at different power outputs between 175 and 300 MW(e), compared to the averaged AP600–AP1000 values, used as a reference.

The figure indicates that, even with the optimistic assumptions made, HTGRs seem to have few advantages over PWRs scaled down to the same power level.

Recently, an improved version of a PBMR was proposed with increased core power density, increased power output, uranium enrichment limited by 8% and a slightly higher fuel burnup, aimed at improving the LUEC [II–1, II–17, II–19]. Table II–16 lists the data used to analyse the economic potential of HTGRs, starting with the values of Tables II–14 and II–15 illustrated by Fig. II–10, and then applying three groups of design changes (steps 1–3) to reach the design of Fig. II–11, while Fig. II–11 shows the corresponding new calculated LUEC values for the power outputs between 175 and 300 MW(e).

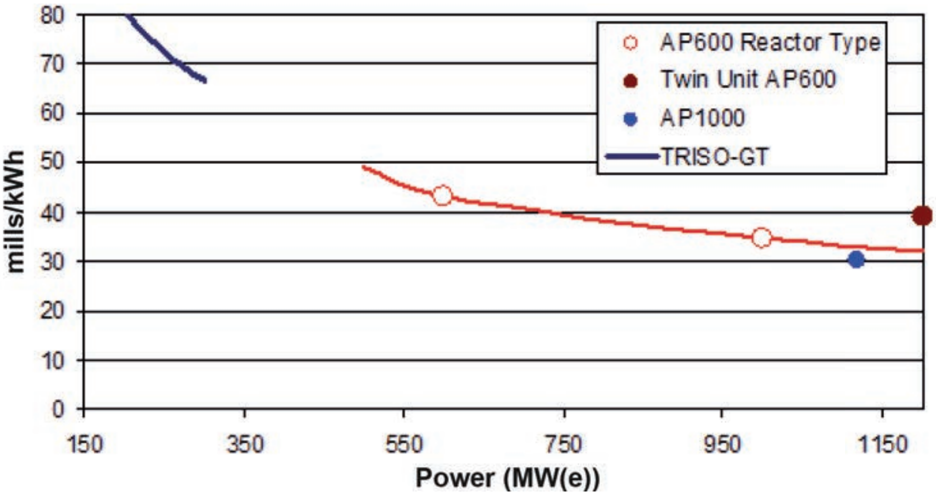

FIG. II–10. Levelized unit energy cost (LUEC) of a high temperature gas cooled reactor (TRISO-GT), scaled between 175 and 300 MW(e), and compared to the LUEC of the AP600 and AP1000 type reactors.

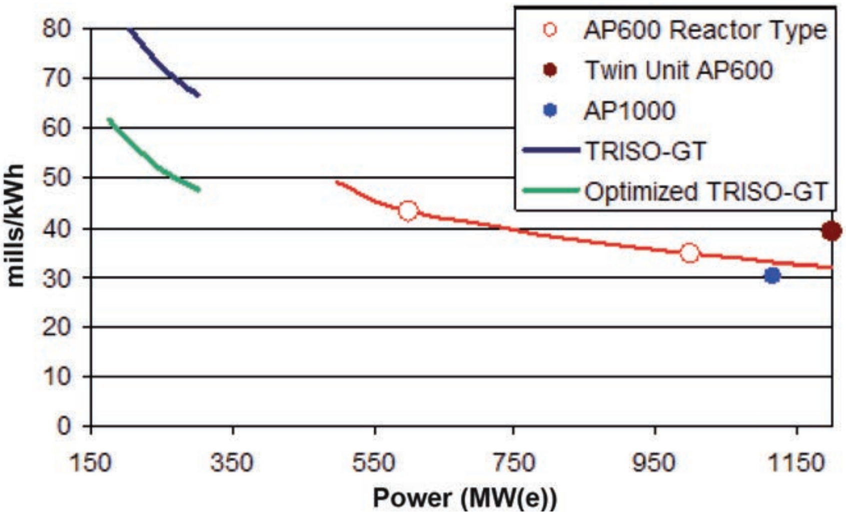

FIG. II–11. Levelized unit energy cost (LUEC) for the averaged high temperature gas cooled reactor (HTGR) (TRISO-GT) and the improved pebble bed modular reactor (PBMR) type HTGR (optimized TRISO-GT), scaled between 175 and 300 MW(e), and compared to the AP600 and AP1000 LUEC values.

II–4.4.2. Results obtained by introducing design changes in groups

To analyse the advantages and disadvantages of the proposed model, evaluation of LUEC was carried out via a sequential introduction of the design changes arranged in groups. The whole process included four steps, considered to show the evolution and the economic advantages of different design alternatives.

The first design change (actually, a zero one) is to take as a reference the original PBMR design concept offering an electric output of 165 MW(e), but to define all other variables equal to the average values of the HTGR (TRISO-GT) reactors. This case is shown in the Design group 1 column of Table II–16 and corresponds to the data of Table II–15.

The second design alternative (step 1 in Table II–16) is to introduce some specific design features of an optimized PBMR with significantly lower uranium enrichment. This would represent a design change directly targeted at the improvement of plant economics.

The third design alternative (step 2 in Table II–16) takes the advantages of the second design alternative, but adds the increased core power density.

The fourth design alternative (step 3 in Table II–16) takes the advantages of the third design alternative, but adds a higher power output and a higher efficiency offered by a larger size of helium turbomachinery.

TABLE II–16. DATA USED TO ANALYSE THE ECONOMIC POTENTIAL OF HTGRs

Item	Design group 1	Design group 2 (step 1)	Design group 3 (step 2)	Design group 4 (step 3)	Units
Power	165	165	165	286	MW(e)
Efficiency	44	44	44	47.7	%
Power density (inverse)	0.02	0.02	0.03	0.03	t U/MW(e)
RPV weight	1 457	1 457	956	1 256	t
Fuel enrichment	11.9	8	8	8	%
Fuel burnup	98 200	80 000	64 800	82 600	MW·d/t U

Note: HTGR: high temperature gas cooled reactor; RPV: reactor pressure vessel.

Table II–16 shows the data used in these calculations, and Table II–17 gives LUEC values calculated for AP600 and AP1000 type PWRs and for the PBMR type design concept, starting with the values of Tables II–14 and II–15 illustrated by Fig. II–10, and then by applying the three steps of the design changes to reach the design of Fig. II–11. Figure II–12 shows the impact of each group of design changes produced on the way from the original PBMR with averaged HTGR values to an optimized PBMR. Figure II–13 shows the break-down of the LUEC values calculated for these four design alternatives, compared to the corresponding values for a PWR at 600 and 300 MW(e).

TABLE II–17. LUEC VALUES CALCULATED FOR AP600, AP1000 AND PBMR DESIGN CONCEPTS

Item	PWR	PWR	Design group 1	Design group 2	Design group 3	Design group 4	Units
Power	600	300	164	164	164	268	MW(e)
Total investment	1850	1249	1251	1108	904	1200	million $
Overnight cost	1550	2092	2823	2826	2462	1860	$/kW(e)
Amortization cost	28.4	38.7	49.6	49.7	42.7	31.9	mills/kW·h
O&M cost	7.8	15.6	3.0	3.0	3.0	2.3	mills/kW·h
Fuel cost	7.1	10.6	36.6	25.2	19.8	13.7	mills/kW·h
Total cost	43.3	64.9	89.2	77.9	65.5	47.9	mills/kW·h

Note: LUEC: levelized unit electricity cost; O&M: operation and maintenance; PBMR: pebble bed modular reactor; PWR: pressurized water reactor; 1 mill = $\$10^{-3}$.

Figure II–12 indicates that each considered group of design changes is very important to improve the economy of the considered PBMR type design concept. Figure II–13 indicates that, when the whole set of design changes is implemented, the PBMR design alternative becomes cheaper than the PWR at 300 MW(e), and even close to the PWR at 600 MW(e).

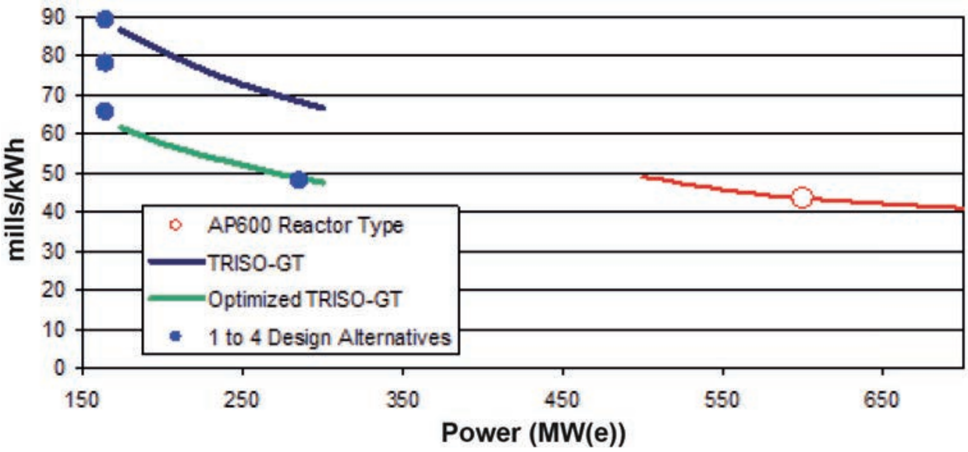

FIG. II–12. Levelized unit energy cost (LUEC) of the pebble bed modular reactor (PBMR) type design concept (TRISO-GT) with high temperature gas cooled reactor (HTGR) average and optimized design values, scaled between 175 and 300 MW(e), and compared to the LUEC of the AP600 type design. Filled dots show LUEC for the four design alternatives on the way from the averaged to the optimized PBMR type design concept

When different components of the costs are compared (Fig. II–13), the PBMR type design concept appears to be cheaper in capital cost, but more expensive in fuel cost, compared to a PWR. Being balanced, these cost differences result in a similar overall contribution to the LUEC. Then, it is a difference in the O&M costs that finally makes the optimized PWR cheaper and comparable to a PWR with a doubled power output.

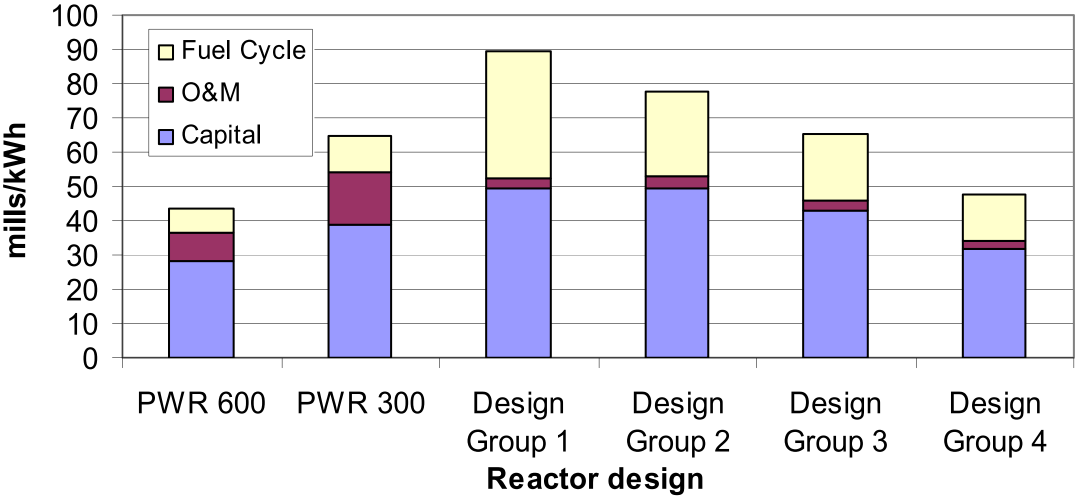

FIG. II–13. Levelized unit energy cost for the AP600 design concept and the AP600 design concept scaled down to 300 MW(e), compared to the pebble bed modular reactor (PBMR) type design concept at 168 MW(e) (design group 1) and then to the PBMR type design concepts incorporating the design changes implemented in three sequential steps (design groups 2–4). O&M: operation and maintenance; PWR: pressurized water reactor.

The last difference on the LUEC should, however, be considered with caution because the model used does not include details of the O&M costs, and also the PWR type reactors are based on hundreds of reactor-years of operation, which is not the case for HTGRs.

In addition, the whole of the comparison needs to be considered with caution because the AP600 costs used are costs for a nuclear reactor in the United States of America (USA), while, for example, the PBMR was developed in South Africa, where the costs and prices are very different from the USA. Even so, the value of $1200 million for total plant investment is in agreement with the published value for the first PBMR to be built in South Africa. If the fuel facility and all the engineering and development costs are included, the value is $2000 million [II–20].

If we consider that the PBMR is being designed for multimodular commercial plants with a standard configuration of four PBMR modules per plant, the relevant additional savings may be between 5 and 15%, and the final total LUEC would then range between 40 and 42 mills/kW·h, making the plant very competitive for US conditions (to which the data used in the model correspond).

II–5. MINIMUM DATASET FOR COMPARATIVE LUEC EVALUATION

To facilitate further applications of the proposed method, the variables of Table II–4 could be presented in a more general form, as a minimum set of scaling variables for the economic comparison of different design options of advanced reactors. Table VII–18 is a data sheet of scaling variables for economic comparison of advanced reactors.

TABLE II–18. DATA SHEET OF SCALING VARIABLES FOR ECONOMIC COMPARISON OF ADVANCED REACTORS

Variable	Units	Value
Electric power	MW(e)	
RPV weight	t	
Number of fuel elements		
Fuel length	m	
Weight of steam generators or primary system heat exchangers (each)	t	
Thermal power	MW(th)	
Volume of RPV vessel	m^3	
For liquid primary coolant: pump power (each) For gaseous primary coolant: volumetric flow rate	MW(e) m^3/s	
Number of primary coolant drivers (pumps or gas blowers)		
Number of steam generators or primary heat exchangers		
Fuel enrichment by fissile material	% by weight	
Core power density	MW(th)/t HM	
Average discharge burnup	MW(th)·d/t HM	
Number of refuelling zones		
O&M costs	mills/kW·h·MW(e)	
Fuel manufacturing costs	\$/kg HM	
Conversion costs for fuel material	\$/kg HM	
Cost of initial fissile raw material	\$/kg HM	
Initial enrichment of raw material	%	
Effective construction time	a	
Contingency factor	Appropriate units	
Average load factor	%	

Note: HM: heavy metal; O&M: operation and maintenance; RPV: reactor pressure vessel; 1 mill = \$$10^{-3}$.

In addition, the *K* factors defined by Eq. (II–9) would need to be specified to produce a complete minimum set of data for the assessment of design changes of an advanced reactor targeted at achieving simplicity and benefits in costs, and taking into account the associated trade-offs. Table II–19 gives a list of the *K* factors that should be determined relative to a reference light water reactor design of the same capacity as that of the reactor being analysed.

TABLE II–19. LIST OF *K* FACTORS

K Item	Value
(1.1) Conventional building	
(1.2) Turbogenerator system	
(1.3) Electrical systems (excluding the generator)	
(1.4) Condenser or heat transfer to heat sink	
(1.5) Other miscellaneous equipment	
(2.1) Containment or confinement	
(2.2) Core structures, baffle, associated reactor internals	
(2.3) Control rod system	
(2.4) Primary to secondary heat exchangers (steam generators or recuperators)	
(2.5) Spent fuel management	
(2.6) Instrumentation and control	
(2.7) Coolant management and control	
(2.8) Primary pumps or compressor, pressure regulation system	
(2.9) Other reactor equipment	
(3.1) Special equipment, for reactor mounting	
(3.2) Engineering	
(3.3) Fixed indirect costs	
(3.4) Indirect conventional costs	
(3.5) Indirect nuclear costs	

II–6. CONCLUSION

A method has been proposed for evaluation of the economic impact of design changes targeted at achieving design simplicity in advanced reactors and, specifically, SMRs. The proposed method is not intended for determination of LUEC values that could be used in economic justifications of certain reactor concepts; it is a tool devised to help the designer screen different design options from an economic perspective at the early stages of a new reactor project. The examples presented in this annex should be viewed only as examples of how the method could be applied, and not as economic evaluations or comparisons of certain advanced reactor design concepts.

For the examples presented in this annex, generic conditions for the LUEC were assumed without taking into account any specific local conditions and any specific policies different to pure capital amortization and recovery of the expenditures with a given discount rate. Therefore, the results presented may not be valid in certain real conditions. Just to illustrate this, the fuel for a transportable reactor such as the BN-GT 300 could, in real life, be the property of a third party, and then it should not be included in the LUEC calculation using Eq. (II–3).

On the other hand, the consistency of the numbers produced by the proposed very simple calculation method appears to be reasonably high when compared to a relatively large spread observed between the data on commercial power reactors of the same type and capacity as published in different countries.

Treating the data on relative costs, the method could be effectively used to study the trade-off between advantages and disadvantages of several design changes, design approaches or just new ideas for reactor design concepts.

In the examples presented, the method has shown a discriminative power sufficient to analyse a variety of interrelated design changes, including transitions from one reactor technology to another. The uncertainties intrinsic to this generic evaluation model are likely to introduce uncertainties in the absolute numbers of the calculated costs, while the impact of relative changes appears to be analysed adequately enough to enable a valid systematic assessment of the design changes aimed at design simplification.

It is important to note that the *K* factors could be used to calculate not only the *N*th of a kind (NOAK) costs associated with mature, i.e. built and operated, systems and components, incorporating small uncertainty, but could also be used for cost evaluation in the initial engineering phases of a project, and for systems and components that have never been built and operated. For such cases, the costs need to be increased by a factor reflecting the experience of a supplier, the similarity with previous experience and the degree of innovation in a given component or system. These costs are usually called FOAK costs, and could include engineering and development costs.

The proposed method allows including the FOAK costs in the *K* factors. However, it is important that FOAK costs are introduced in a balanced way, and not mixed with the NOAK costs without having a valid reason to do so. The combination of FOAK and NOAK costs executed without a proper check of the scope of the costs and prices could produce very biased results when a given reactor has many innovative features. For example, the LUEC values calculated in this annex for HTGR (TRISO-GT) are NOAK costs because they include no penalization for any improvement performed without engineering knowledge and operating experience, and because the base costs used in the calculations were the published data for the PWR type reactor (AP600).

The *K* factors could also be used to take into account the engineering contingency margin (ECM). This is the margin in cost reflecting the lack of engineering or proven experience for some novel systems or components; it is also referred to as the cost design margin. For example, the values of LUEC calculated for HTGRs include some ECMs because they are NOAK costs based on the data for the AP600 design concept, including the ECM that reflects the cost design margin consistent with the engineering level of the AP600 at the moment of calculation.

The FOAK costs, the NOAK costs and the ECM need to be addressed carefully in calculations to avoid introducing gaps in the cost calculation or double counting of a given item [II–3, II–21].

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Annex III

PROBABILISTIC ANALYSIS OF ELECTRICAL ENERGY COSTS: COMPARING PRODUCTION COSTS FOR GAS, COAL AND NUCLEAR POWER PLANTS

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III–1. INTRODUCTION

The increase in electricity demand is linked to the development of the economy and living standards in each country. This is especially true in those developing countries in which electricity consumption is far below the average of industrialized countries.

To satisfy the increased demand for electricity, it is necessary to build new electrical power plants that could, in an optimum way, meet the imposed acceptability criteria. The main criteria are the potential to supply the required energy and to supply it with minimum or, at least, acceptable costs and environmental impacts, to satisfy the licensing requirements and be acceptable to the public. The main competitors for electricity production in the next few decades are fossil fuel power plants (coal and gas) and nuclear power plants. Power plants making use of renewables (solar, wind, biomass) are also important, but due to limited energy supply potential and high costs, can only be a supplement to the main generating units. Large hydropower plants would be competitive under the condition that suitable sites for the construction of such plants exist. Unfortunately, both in Croatia and in the rest of central Europe, such sites are scarce.

III–2. PROBABILISTIC METHOD TO COMPARE COMPETITIVENESS OF POWER PRODUCING TECHNOLOGIES

Taking into account the above, it is obvious that planning of future electricity generation is to be primarily based on fossil fuel and nuclear technologies. In the recent past, preference among fossil fuel technologies has been given to gas fired combined cycle plants. The preference was based on cost advantages of the generated electricity, on better public acceptance and on lower environmental impacts (compared to coal fired plants).

The cost of electricity generation is certainly a condition of major importance to accept a power plant project. In order to make an appropriate calculation of the cost of generated electricity, it is necessary to include plant costs and load factors during the plant lifetime. This is achieved by calculating the levelized lifetime busbar electricity cost. It is a fictitious average cost depending upon the discount rate and the predicted changes of costs and load factors during plant operation. The advantage of using levelized electricity costs for a comparative competitiveness assessment of different power producing technologies is the possibility to investigate the impact of changes of some parameters that have a strong influence on generation costs (such as changes of fossil fuel cost), during plant lifetime.

It is clear that such calculations would contain numerous uncertainties. Due to a considerable uncertainty in the prediction of long term changes in the relevant parameters (costs and load factors), it is more justified to perform calculations using a probabilistic rather than a deterministic method. The objective of this annex is to summarize the methodology of the probabilistic analysis, to present distributions of the calculated levelized costs of generated electricity, and to compare such distributed costs for a coal fired power plant, a gas fired power plant and a nuclear power plant.

Each cost term used in the calculation has a certain uncertainty margin and a certain probabilistic distribution within this margin. Additionally, the terms of a cost could be correlated positively or negatively, with correlation values between one (fully correlated) and zero (non-correlated). The appropriate input values have to be defined by using a best estimate approach. After defining the variables with ranges, the distribution within the ranges and the correlations, probabilistic distributions of calculated electricity costs need to be obtained by taking into account the defined uncertainty margins. The standard approach to achieve this is to calculate electricity cost using random values (Monte Carlo method) of each cost item within a given uncertainty range. A large number of such calculations is required to obtain a meaningful probabilistic distribution of the results. Use of an appropriate computer code capable of handling the necessary number of variables is indispensable to obtain valid distributions of levelized electricity costs.

The variables used in probabilistic analysis to compare the competitiveness of the considered power technologies are:

- Overnight specific investment cost in \$/kW;
- Constant operation and maintenance cost in \$/kW;
- Variable operation and maintenance cost in \$/kW·h;
- Fuel cost in \$/GJ;
- Plant efficiency;
- Capacity factor;
- Years of loan repayment;
- Years of plant lifetime;
- Discount rate;
- Average interest rate for loan repayment;
- Average rate of a foreseen fuel price change during the plant lifetime.

The analysis is performed in the following steps:

(a) The expected range of uncertainty for plant performance and the cost variables that affect the levelized cost of electricity are defined;
(b) Probabilistic distributions within the ranges and correlation factors for each key input variable are predicted;
(c) Monte Carlo analysis is used to generate random inputs for the calculation of levelized electricity costs on the basis of the described uncertainties;
(d) A reasonably large number of calculations are performed to obtain meaningful probabilistic distributions of the results.

The analysis described above generates the probabilities and the cumulative probability distributions for levelized costs of electricity for each of the compared technologies, using probability distributions developed for the input variables. The process includes the generation of a large number of random samples of the input variables and the corresponding values of the levelized electricity generation costs. The probability distributions for the levelized electricity generation costs are obtained by counting the number of times each value of the performance parameter occurs.

III–3. EXAMPLE OF PROBABILISTIC COST ANALYSIS FOR ELECTRICITY GENERATED BY DOMINATING POWER TECHNOLOGIES

As part of the studies carried out for electrical system expansion analysis in Croatia for the period 2010–2030, the probabilistic method was applied to compare best estimate differences in levelized lifetime costs of electricity generated by promising power producing technologies. The technologies compared were a combined cycle gas fired plant, a conventional (non-innovative) coal fired plant and a nuclear power plant with a light water reactor [III–1].

Additionally, wind plants were also included in the comparison. Analysis of the electrical system of Croatia has shown that, because electricity production in wind plants is of a stochastic nature and as it is necessary to maintain the security of the electricity supply, construction of new wind plants cannot reduce the necessary new capacity of fossil or nuclear plants. The operation of wind plants should be linked to the operation of a flexible power generator (such as a gas fired plant) that is capable of replacing the missing capacity promptly. For this reason, the levelized generating cost of a wind plant could be analysed jointly with the associated gas fired plant as the levelized production cost of a synthetic power generator whose investment cost is a sum of the investment costs of a wind and a gas fired plant and whose gas consumption corresponds to the consumption of a gas fired plant reduced by a factor depending upon the average capacity factor of a wind power generator. For future investments, the influence of learning has been taken into account with respect to wind power generators [III–2].

The analyses targeting future predictions in the real word involving elements of the uncertainty are usually too complex to be carried out by a deterministic analytical method. There are simply too many combinations of the input values to calculate every possible result. Monte Carlo simulation is an efficient technique for the analysis of such problems. It is a simple technique that requires only a random number generator to be installed on a computer.

There are numerous computer codes available to handle the described problem. The presented study made use of the stochastic analysis of technology systems (STATS) computer code developed at Argonne National Laboratory. A basic description of the STATS code is given in Ref. [III–3]. This is not a new code, but it is still capable of producing usable results. An update of the code to make it more user friendly, to improve the presentation of results and to expand its capability would be recommendable.

The STATS model was originally developed to estimate composite uncertainty distributions for various systems and technologies. It provides a convenient approach for treating the uncertainties and correlations between cost and performance components. The approach has the capacity to provide improvements in comparisons based simply on combinations of best point estimates. The additional information developed in uncertainty analysis is useful for considering the relative risks and benefits of the technology or system expansion options.

The code calculates composite uncertainty distributions based on user defined component uncertainties. It uses the Monte Carlo method for problem solving. A random number generator is applied to calculate a value for each component; that is, each uncertainty variable is represented as a relative probability function. The code then calculates a composite value by using these selected values for all of the components, as prescribed by the user specified functional relationship between these values. As random draws are used to calculate every component value (from the relative probability functions), the composite values also contain random variations. By repeating the above procedure many times and storing all of the results, an uncertainty distribution for the composite values can be constructed that reflects the net effect of the component uncertainties.

The model allows a selection between the three distribution types of input data: uniform distribution, triangular distribution and five point distribution.

Selection of the correct probability distribution is possible if there is reliable information about the ranges of uncertainty of the variables from historical data. If historical data are not available, an expert judgement should be applied, based on past knowledge about the range of variation of particular input data. The results are then sorted and plotted in the form of a probability distribution and a cumulative probability distribution.

The discounted cost of electricity generation (called the ‘levelized busbar cost’) in the period of loan repayment and in the following period until the end of the plant lifetime is given by:

$$c_{\mathrm{el}} = \frac{\sum\limits_{k=1}^{k=n_{lr}} \frac{1}{(1+p_{\mathrm{d}})^k} \left[\frac{p_1\, c_{\mathrm{i}}}{1-(1+p_1)^{-n}} + c_{\mathrm{com}} + 8760\ L_{\mathrm{f}} \left(\frac{c_{\mathrm{f}}\,(1+p_{\mathrm{f}})^k}{277.8\eta} + c_{\mathrm{vom}} \right) \right]}{\sum\limits_{k=1}^{k=n_{\mathrm{lr}}} \frac{8760\ L_{\mathrm{f}}}{(1+p_{\mathrm{d}})^k}} + \frac{\sum\limits_{k=n_{\mathrm{lr}}}^{k=n_{\mathrm{pl}}} \frac{8760 f}{(1+p_{\mathrm{d}})^k} \left(\frac{c_{\mathrm{f}}\ (1+p_{\mathrm{f}})^k}{277.8\ \eta} + c_{\mathrm{vom}} \right)}{\sum\limits_{k=n_{\mathrm{lr}}}^{k=n_{\mathrm{ltm}}} \frac{8760\ L_{\mathrm{f}}}{(1+p_{\mathrm{d}})^k}} \qquad \text{(III–1)}$$

where

c_{com} is the constant operation and maintenance cost in \$/kW;
c_{el} is the levelized cost of the produced electrical energy in \$/kW·h;
c_{f} is the fuel cost in \$/GJ;
c_{i} is the overnight specific investment cost in \$/kW;
c_{vom} is the variable operation and maintenance cost in \$/kW·h;
f is the index for fuel;
η is the plant efficiency;
L_{f} is the load factor;

n_{lr} is the number of years of loan repayment;
n_{ltm} is the average long term efficiency;
n_{pl} is the number of years of plant life;
p_{d} is the discount rate;
p_{l} is the average interest rate for loan repayment;

and p_{f} is the average rate of the foreseen fuel price change during the plant lifetime.

III–3.1. Input data for the analysis

Input data used in the analysis of levelized costs of fossil and nuclear plants are indicated in Table III–1. The data for a wind–gas synthetic power generator are not included.

TABLE III–1. ESTIMATED COST DATA WITH EXPECTED RANGES OF UNCERTAINTY AND PROBABILISTIC DISTRIBUTIONS

Plant type	Nuclear	Coal	Combined cycle gas
Overnight specific investment cost — c_{i} (\$/kW)			
Distribution	Triangular	Triangular	Triangular
End values	1900 2000 2100	1400 1500 1600	500 600 700
Constant operation and maintenance cost (no fuel) — c_{com} (\$/kW)			
Distribution	Flat	Flat	Flat
End values	100 120	30 40	10 20
Variable operation and maintenance cost — c_{vom} (¢/kW·h)			
Distribution	Flat	Flat	Flat
End values	0.15 0.25	0.30 0.40	0.15 0.25
Fuel cost (\$/GJ)			
Distribution	Five point	Five point	Five point
End values	0.45 0.475 0.5 0.525 0.55	1.8 1.9 2.0 2.1 2.2	4.0 4.25 4.5 4.75 5.0
Plant efficiency			
Distribution	Flat	Flat	Flat
End values	0.32 0.34	0.38 0.42	0.54 0.62
Load factor			
Distribution	Triangular	Triangular	Triangular
End values	0.6 0.7 0.8	0.5 0.6 0.7	0.4 0.5 0.6

TABLE III–1. ESTIMATED COST DATA WITH EXPECTED RANGES OF UNCERTAINTY AND PROBABILISTIC DISTRIBUTIONS (cont.)

Plant type	Nuclear		Coal		Combined cycle gas	
Years of loan repayment						
Distribution	Flat		Flat		Flat	
End values	15	20	15	20	12	15
Years of plant lifetime	40		35		30	
Discount rate (%)						
Distribution	Flat		Flat		Flat	
End values	5	8	5	8	5	8
Average interest rate for loan repayment (%)						
Distribution	Flat		Flat		Flat	
End values	5.5	7.5	5.5	7.5	5.5	7.5
Average annual rate of fuel price increase (%)						
Distribution	Flat		Flat		Flat	
End values	0.8	1	1	2	2	5

Each of the indicated cost parameters, rates and durations of loan repayment is characterized by an uncertainty range and a distribution within the range, as also given in Table III–1. These data are based on the best engineering judgement for plants entering commercial operation between 2000 and 2020.

III–3.2. Fuel costs

The expected rate of fuel cost increases during plant operation would be different for different types of fuel because of the expected different market conditions that are, in turn, influenced by the expected demand and reserves.

It is reasonable to expect a higher rate of increase of gas costs compared to coal costs and nuclear fuel costs, owing to the expected high gas demand and shortage of gas supplies after the year 2020. Some justification for such an expectation is provided by the following discussion.

From the analysis of many references (e.g. Ref. [III–4]), it can be deduced that a considerable difference between the expected gas production and demand can be foreseen in some regions of the world in the next two decades. Table III–2 provides a summary of such differences.

It can be seen from the table that in the next few decades, there are three regions in the world for which a large deficit of gas is foreseen and which, therefore, may require a large import of gas. These are central and east Asia, North America and, especially, western and central Europe. As the routes of gas supply to Croatia are linked with central and western Europe, it could be expected that ‘frictions’ in the gas market could occur and that large investments in gas lines and new resources would be necessary. It can be foreseen that the gas market will tend to be more monopolistic in the future. This condition will certainly stimulate an increase in the gas price. In addition, gas users are not only utilities, but also industry and households. These users are not flexible in switching fuel and can accept higher gas prices than utilities. For these reasons, they will have priority of gas supply in the case of a shortage (such a situation has already been experienced in Croatia during winter-time).

TABLE III–2. EXPECTED DIFFERENCES BETWEEN NATURAL GAS PRODUCTION AND DEMAND IN WORLD REGIONS IN THE YEARS 2010, 2020 AND 2030

World region	Difference between natural gas production and demand (billion m^3)		
	2010	2020	2030
Africa	+63	+44	+15
Central and east Asia	−200	−286	−361
South-east Asia and Oceania	+68	+47	+25
East Europe and north Asia	+153	+135	+67
Middle East	+53	+71	+76
North America	−98	−147	−228
South America	−3	−15	−42
Western and central Europe	−270	−411	−533

On the other hand, the expected demand for coal and nuclear fuel is likely to remain modest, as the reserves are large, and there is no reason to expect a substantial long term rise of prices for these fuels.

For this reason, it was estimated that a lifetime average annual cost increase for coal and nuclear fuel during the plant lifetime will be in the ranges 1–2% and 0.8–1%, respectively, and for natural gas, in the range 2–5%. The average cost increase rates for natural gas, when estimated in dollars (current) on the basis of recent experience, seem to be on the optimistic side. If underestimated, these cost increase rates would favour fossil fuel (particularly, gas) plants compared to nuclear plants because of the larger impact of gas fuel cost on the cost of the electricity produced.

The average load factor achieved during the lifetime of the compared plants is affected by their variable costs. It is expected to be the highest for a nuclear power plant (0.6–0.8), somewhat lower for a coal fired plant (0.5–0.7) and the lowest for a gas fired plant (0.4–0.6).

All data necessary to calculate the cost of electricity generated by the three different plants are given in Table III–1.

III–3.3. Results of the analysis

The analysis has produced probabilistic distributions of levelized electricity costs for three different technologies (gas fired combined cycle plant, coal fired plant and nuclear power plant) by using the probability distributions of the input variables from Table III–1. In total, 2000 cost calculations using Eq. (III–1) were carried out, and 50 cost intervals were selected for this analysis. The results obtained with the STATS code were rearranged using an Excel sheet to produce the curves shown in Figs III–1 to III–5.

The results have been obtained based on the assumption that no correlations exist between the variables. In the cases where there is sufficient evidence to assume a certain degree of correlation, the width of the obtained cost distribution would narrow.

Figures III–1 and III–2 present distributions of the cost of electricity generated in a coal and a gas fired plant, while Fig. III–3 provides a comparison of these costs with the cost of electricity generated in a nuclear power plant. The levelized electricity costs are plotted against the corresponding numbers of the results of a random calculator.

The figures provide information on the number of random calculations of costs for each cost interval. A cost interval with the largest number of random calculation results is then the most probable cost interval.

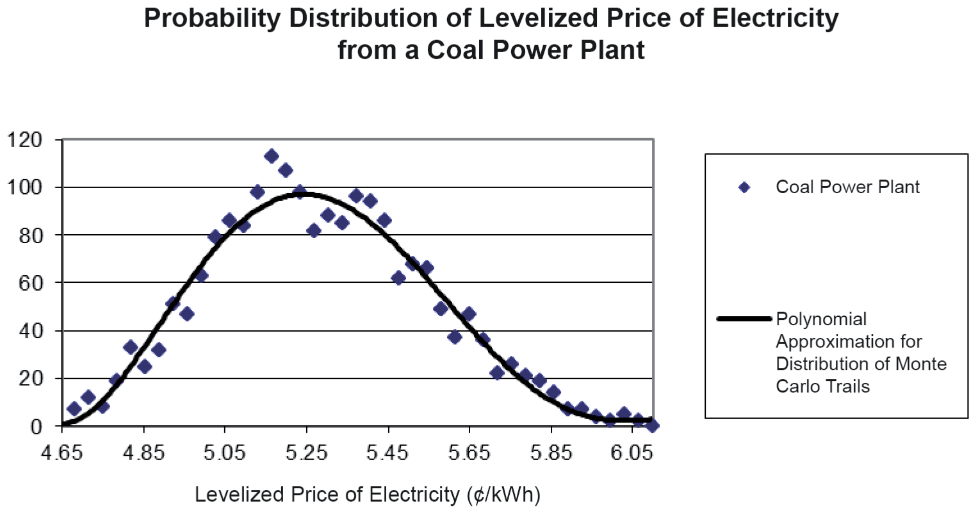

FIG. III–1. Distribution of levelized cost of electricity from a coal power plant.

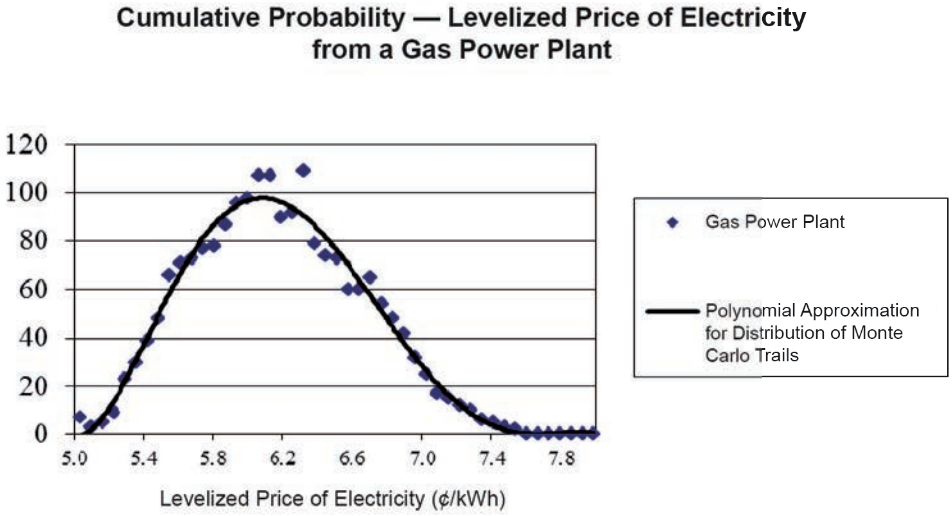

FIG. III–2. Distribution of levelized cost of electricity from a gas power plant.

In order to facilitate comparison of the levelized costs of electricity produced in coal, gas and nuclear plants, in Fig. III–3, the results given previously in Figs III–1 and III–2 are plotted jointly with the results obtained for a nuclear power plant.

It can be seen that, on the basis of the input data given in Table III–1, nuclear and coal power plants would, considering the total plant lifetime, produce less expensive electrical energy than a natural gas combined cycle plant. This is mainly due to the expected future increase of gas cost, and a large contribution of fuel costs to the electricity costs in gas fired plants. It can be seen from the graphs that the distribution of levelized busbar costs for the combined cycle gas plant is in the range of 5–7.5¢/kW·h, with a most probable value of about 6.1¢/kW·h. For coal fired plants, the corresponding values are 4.5–6¢/kW·h, with a most probable value of about 5.2¢/kW·h. Most favourable cost figures are observed for a nuclear power plant with a distribution in the range of 4.2–5.8¢/kW·h, and a most probable value of about 4.8¢/kW·h.

The figure shows that the electricity cost produced in a nuclear plant is lower than in both fossil fuel plants (most probable levelized cost values are about 0.4¢/kW·h lower than in a coal fired plant and about 1.3¢/kW·h lower than in a combined cycle gas fired plant).

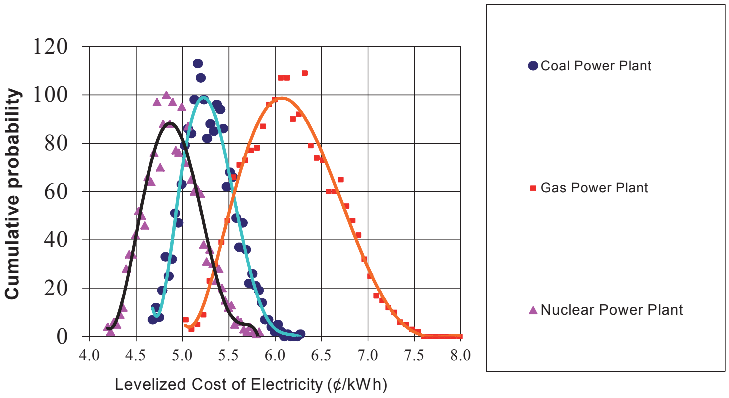

FIG. III–3. Distribution of levelized costs of electricity from a coal, a gas and a nuclear power plant.

The results given in Figs III–1 to III–3 are generally sufficient to illustrate the relative merits of the considered technologies. However, they could be processed further to obtain more information, if required. This additional information could be the distribution of cost differences or quantification of a probability that the cost of electricity produced by one technology will be higher or lower than that from the other technology.

As an example, Fig. III–4 shows a distribution of the cost differences for electricity generated in a coal fired power plant versus a gas fired power plant.

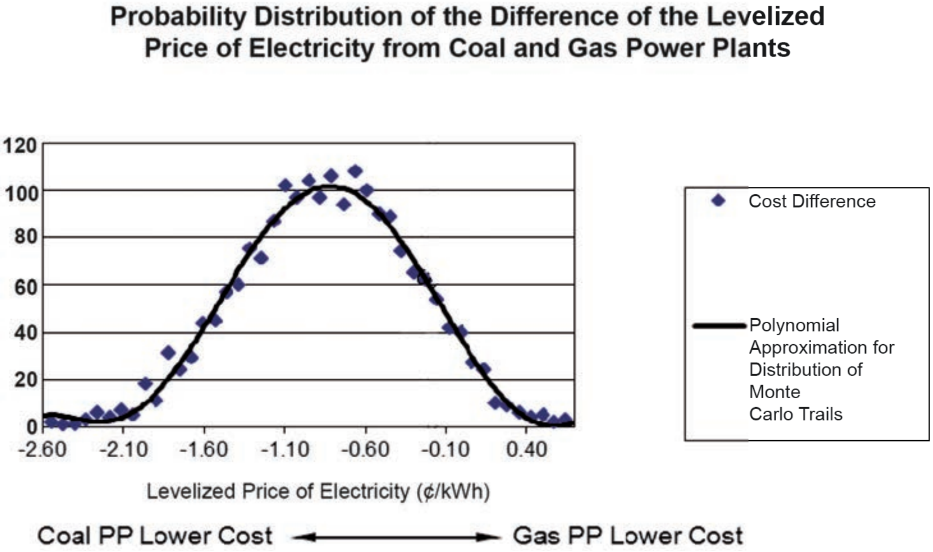

FIG. III–4. Distribution of differences of levelized costs of electricity from a coal and a gas power plant.

Similarly, the distribution of differences of the levelized costs of electricity from a coal and a nuclear power plant is given in Fig. III–5.

The most probable electricity cost difference between coal and gas plants is about −0.9¢/kW·h, ranging from –2.5 to +1¢/kW·h. On the other hand, the electricity cost difference between a coal fired and a nuclear power plant is in the range –0.8 to +1.5¢/kW·h, with a most probable value of about +0.4¢/kW·h. This information can also be extracted directly from Fig. III–3.

By counting positive and negative cost differences in Figs III–4 and III–5, it can be concluded that the probability for a coal fired power plant to be more economical than a combined cycle gas fired plant is about 95%, and the probability that electricity produced in a coal fired plant will be less expensive than electricity produced in a nuclear plant is only about 15%.

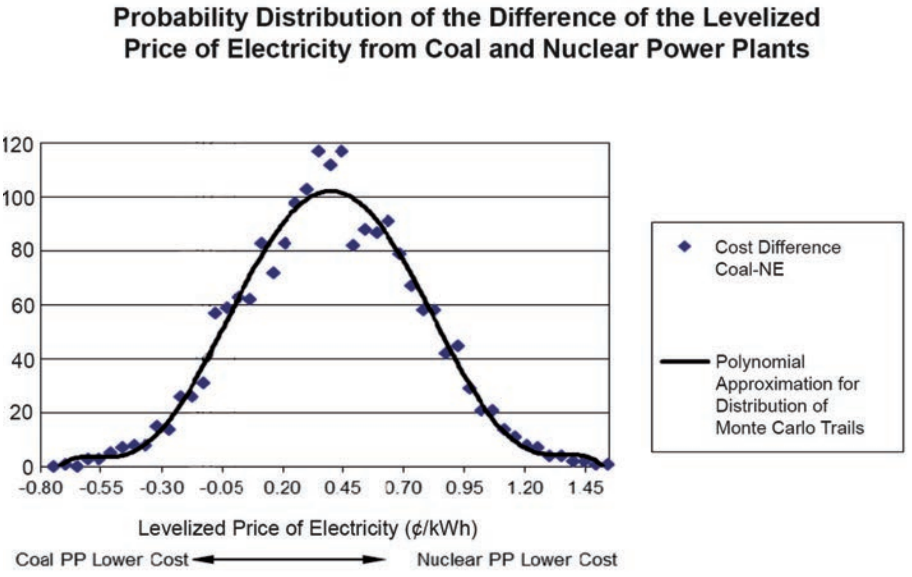

FIG. III–5. Distribution of difference of levelized price of electricity from a coal and a nuclear power plant.

Notwithstanding the fact that the numerical values given in Table III–1 are best estimate values, it is, of course, possible to perform a sensitivity study by modifying these values.

III–4. ENVIRONMENTAL IMPACTS AND POWER PLANT ECONOMICS

The use of electricity is, apart from the benefits it brings, linked to numerous environmental and social problems. Electricity production is associated with air, water and soil pollution, potentially affecting health, buildings, crops and forests, and causing global warming, as well as occupational diseases. In addition, it could cause accidents and a reduced amenity from visual intrusion of a plant or from noise emissions. So far, there is no full consensus among energy planners on how such damages in the environment, referred to as external costs, could be reflected in the market price of electricity and used as a factor in electrical system development planning. It is not possible to discuss these problems in detail in the framework of this annex.

A variety of methods are available for reducing external factors, ranging from the development of new technologies to imposition of emission limits and use of economic instruments, such as emission charges. However, in order to specify an optimum environmental policy, it is necessary to quantify the expected damage to the environment. In this way, it could be possible to weigh up the benefits of the administrative or abatement measures against the external costs.

Within the European Commission’s ExternE project (ExternE 1995, 1998 update [III–5]), a unified bottom-up methodology was developed to calculate external factors of various power generation technologies and their fuel chains. The approach, called the impact pathway methodology, is a comprehensive and scientifically grounded procedure applied to quantify damages to human health and the environment. It follows the chain of linkages between the burden emitted into the environment, its dispersion in the receiving media, its physical impact on human health and/or the environment, and finally evaluates the impacts in monetary terms.

One of the biggest achievements of the ExternE project is the compilation of a database of physical data on the burdens and impacts of energy systems. Apart from that, monetary values of human health and environmental impacts were established, allowing quantification of external costs. The calculated external costs can then be used in a range of issues:

- Cost–benefit analysis of pollution abatement measures;
- Optimization of site selection processes;
- Internalization of external costs of energy;
- Comparative assessment of energy systems.

The ExternE project quantifies the health and environmental damage caused by a full energy cycle of power producing technologies. The damage includes health damage due to emissions of solid particles and aerosols, and expected damage in the environment due to emissions of greenhouse gases. The results of the study indicate the following external costs for the considered technologies (Table III–3).

TABLE III–3. EXTERNAL COSTS OF ELECTRICITY GENERATION TECHNOLOGIES

Plant type	Value of external costs (€/kW·h)	Basis for calculating external costs
Pulverized coal fired plant	0.064	Value of years of life lost
Combined cycle gas fired plant	0.021	Value of years of life lost
Nuclear power plant	0.0025–0.0073	Value of statistical life

Case studies of external costs in European countries [III–6] have shown a large spread of results; the average values of such costs are given in Table III–4.

TABLE III–4. VALUES OF EXTERNAL COSTS FOR EUROPEAN COUNTRIES

Plant type	External costs (10^{-3} €/kW·h)
Coal and lignite	39.5–72.2
Gas	11.5–23.2
Nuclear	3.9–4.5
Wind	1.23–1.78

To include the impact of environmental damage costs into a power plant evaluation, it is necessary to combine, in a certain way, the external costs with the variable operation and maintenance costs of the plant (to perform the so-called internalization of the external costs). It is quite obvious that adding the total or a part of the external costs[1] given in Table III–3 or III–4 to the values of c_{vom} (variable operation and maintenance cost) given in Table III–1 would result in a considerable decrease in the competitiveness of fossil fuel (particularly, coal) power plants versus nuclear power plants. In this, the internalization of the external costs given in Table III–3 would almost double the cost of electricity produced in a coal fired plant and increase the cost produced in gas fired plants by about 30%. On the other hand, the influence of external costs on the increase in electricity cost produced in a nuclear power plant would be limited to about 10%. It is, therefore, clear that adding external costs to the variable operational costs in Eq. (III–1) would essentially improve the position of nuclear power relative to coal and gas technology, as compared to that shown in Fig. III–3.

The environmental impact of power plants is becoming one of the key issues in the decision making process associated with the selection and construction of power plants. Referring to this, it can be assumed that at least a portion of the environmental damage expressed in external costs might be included as a factor in future electrical system expansion planning.

It should be noted that external costs presently do not cover all possible environmental damage (e.g. damage to vegetation and forests resulting from atmospheric emissions). Further difficulty in applying external costs is in the fact that they are, to a large extent, country specific (the values given in Tables III–3 and III–4 correspond to

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[1] A margin and the distribution of occurrence could also be attributed to these costs.

the European Union only). This is because the estimates of the external costs are based on the values of statistical life (VSL) and the value of years of life lost (YOLL). Both values reflect the country's economic strength to invest a certain amount of funds (in health care, transport security, etc.) to save a statistically defined number of human lives (the so-called 'willingness to pay' concept). The values of VSL and YOLL, and the corresponding external costs, are likely to be lower in developing countries than in industrialized countries. As a first approximation, it could be assumed that the external costs are proportional to the national gross domestic product.

Environmental impacts of future power plants are one of the key issues in their evaluation. Because of this, studies of competitiveness of power producing technologies should also include analyses of external cost impacts.

III–5. CONCLUSION

Today, even with the use of powerful computers and comprehensive models, accurate forecasting of the development of power systems is very difficult. Uncertainties are present in nearly all types of analyses and studies, especially in those that deal with future events. Stochastic analysis can help in dealing with the uncertainties related to future plant costs and operation by exploring to what extent the uncertainties in the basic input values would reflect in the uncertainties of the composite values (such as the levelized electricity cost). This could help decision makers navigate through difficult situations affected by future uncertainties.

Deterministic approaches can provide a range of plausible so-called 'scenarios', but the important information would be missing regarding the likelihood of various alternative developments. The strength of probabilistic approaches, such as the one described in this annex, is that complete ranges of possible values of the key parameters could be treated simultaneously. The combined effects of uncertain components and correlations are explicitly calculated in order to provide a consistent basis for comparison. These probabilistic methods are particularly helpful when the number of uncertain inputs is large.

This annex has presented a framework for the analysis of uncertainties related to comparison of the main technologies competing for increased electricity production in the next few decades.

REFERENCES TO ANNEX III

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[III–2] McDONALD, A., SCHRATTENHOLZER, L., Learning rates for energy technologies, Energ. Policy **29** (2001) 255–261.

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[III–4] BOUCHARD, G., LALLEMAND, I., "Development prospects for natural gas worldwide 2000–2030", paper presented at the Int. Congr. of World Energy Council, Houston, 1998.

[III–5] EUROPEAN COMMISSION, ExternE, 1995/98 Externalities of Energy, European Commission, Directorate General XII, Brussels.

[III–6] EUROPEAN COMMISSION, External Costs, Research Results on Socio-environmental Damages due to Electricity and Transport, EUR 20198, European Commission, Brussels.

Annex IV

POSITIVE EXPERIENCE WITH SMALL AND MEDIUM SIZED REACTORS IN INDIA, LESSONS LEARNED IN THE PREVIOUS TWO DECADES AND FUTURE PLANS

Nuclear Power Corporation of India Limited, India

IV–1. OPERATING SMALL AND MEDIUM SIZED REACTORS

IV–1.1. Background

India has limited uranium resources and about one third of the world's thorium resources. With a view to utilizing these resources in the country for electricity generation, a long term three stage programme has been evolved as a strategy. At the second International Conference on Peaceful Uses of Atomic Energy in Geneva in September 1957, H. Bhabha and N.B. Prasad presented a paper on a study of the contribution of atomic energy to a power programme in India. This paper elaborated the three stage programme of natural uranium fuelled pressurized heavy water reactors (PHWRs) in the first stage, fast breeder reactors (FBRs) using the spent fuel of the second stage, and thorium based reactor systems in the third stage. This three stage programme has been accepted over the years and still holds good, even today.

The focus in India, from the very beginning of the programme, has been to make nuclear power self-reliant. Towards this objective, development of human resources, research and development for all aspects of the nuclear fuel cycle, and establishment of an infrastructure for the manufacturing of nuclear components within the country were targeted well before launching the nuclear power programme. Some of the initial activities, over a period of time, have been shaped as industrial units of the government, as well as industries in the country. Such an approach has greatly contributed to the self-reliance of the nuclear power programme, in addition to the benefits to the overall industrial infrastructure in the country. The establishment of research reactors, facilities and laboratories to support the nuclear power programme and related fuel cycle activities at the Bhabha Atomic Research Centre, and the Indira Gandhi Centre for Atomic Research for the FBR programme has made a significant contribution to the national capacity in the frontier areas of nuclear science and technology.

IV–1.2. Nuclear power programme

The decision to build the first nuclear power station at Tarapur (Maharashtra) in 1964 on the basis of a turnkey contract with General Electric and the Bechtel Engineering Corporation (United States of America) as architect–engineers marked the beginning of a nuclear power programme in India. Two boiling water reactors of 210 MW(e) each were set up essentially to demonstrate the capability of the Indian grid to accommodate nuclear power reactors and also to gain experience in setting up nuclear power stations. The nominal rating of these reactors was subsequently revised to 160 MW(e) due to the isolation of the secondary steam generators. Both reactors are currently in their 38th year of operation.

In parallel, a decision was made to build two PHWRs of 220 MW(e) each at Rawatbhata (Rajasthan) in collaboration with the Atomic Energy of Canada Limited (AECL). While most of the reactor equipment items for the first unit came from Canada, those for the second unit were fabricated in India. The reactors were put into operation in 1973 and 1981, respectively. The third atomic power station in India was built at Kalpakkam (Tamil Nadu) with full responsibility for the execution of the project resting within the country. The reactors commenced operation in 1984 and 1986, respectively.

In 1987, the nuclear power programme earlier carried out as a governmental activity was transferred to a new company, Nuclear Power Corporation of India Limited (NPCIL), incorporated under the Company's Act. The experience of the past two decades is, therefore, concurrent with the experience of NPCIL since its inception.

Six nuclear power reactors were in operation in 1987. After gaining experience in setting up the first atomic power stations with PHWRs, the design modifications, such as two independent fast acting shutdown systems, a high pressure emergency core cooling system, an integral calandria and end shields, a water filled calandria vault, elimination of the dumping, and provision of the double containment with a modified vapour separation pool, were incorporated into the standard design of the 220 MW(e) reactors. Four such reactors, two each at Narora (Uttar Pradesh) and Kakrapar (Gujarat), were set up. Eight more 220 MW(e) PHWRs, with changes such as steam generators fully inside the primary containment, complete concrete construction and a compact site layout, were subsequently set up at Kaiga and Rawatbhata. These reactors (Kaiga-1–4 and RAPS-3–6) have all been constructed and connected to the grid. With the completion of these reactors, India has established a large number of small and medium sized reactors (SMRs).

The original unit size of about 220 MW(e) was selected based on the nuclear power unit size, the electrical grid capacity and the industrial infrastructure available at that time. This design became a forerunner of the 500 MW(e) PHWR. The operational experience of 220 MW(e) PHWRs and the feedback from construction of these reactors provided significant inputs for the design development of the 500 MW(e) reactor, essentially, an upscaled version of the 220 MW(e) PHWR. The nominal rating was later revised to 540 MW(e), and two PHWRs of this capacity have been set up at Tarapur (Maharashtra). Thus, in the past two decades, nine reactors of 220 MW(e) and two reactors of 540 MW(e) have been put into operation. In addition, construction work is completed for three PHWRs of 220 MW(e) each and two pressurized water reactors of 1000 MW(e) each, introduced as an addition to the indigenous nuclear power programme.

In conjunction with the second stage of the programme, construction of a fast breeder test reactor of 40 MW(th) was started in 1973, and the reactor has been in operation since 1985. The feedback from this activity provided inputs for the design of a 500 MW(e) FBR, the construction of which started in October 2004. These achievements signified the launch of the second stage of the nuclear power programme. The 500 MW(e) FBR is scheduled to be operational in 2013

Table IV–1 gives the reactor location, type, capacity and date of the startup of commercial operation.

Table IV–2 gives the reactor location, type, capacity and targeted date of the startup for the reactors under construction in India.

TABLE IV–1. SUMMARY DATA FOR OPERATING REACTORS IN INDIA

Unit location	Reactor type	Capacity (MW(e))	Startup of commercial operation
TAPS-1 Tarapur, Maharashtra	BWR	160	28 Oct. 1969
TAPS-2 Tarapur, Maharashtra	BWR	160	28 Oct. 1969
RAPS-1 Rawatbhata, Rajasthan	PHWR	100	16 Dec. 1973
RAPS-2 Rawatbhata, Rajasthan	PHWR	200	1 Apr. 1981
MAPS-1 Kalpakkam, Tamil Nadu	PHWR	220	27 Jan. 1984
MAPS-2 Kalpakkam, Tamil Nadu	PHWR	220	21 Mar. 1986
NAPS-1 Narora, Uttar Pradesh	PHWR	220	1 Jan. 1991
NAPS-2 Narora, Uttar Pradesh	PHWR	220	1 Jul. 1992
KAPS-1 Kakrapar, Gujarat	PHWR	220	6 May 1993
KAPS-2 Kakrapar, Gujarat	PHWR	220	1 Sep. 1995
Kaiga-2, Kaiga, Karnataka	PHWR	220	16 Mar. 2000
RAPS-3 Rawatbhata, Rajasthan	PHWR	220	1 Jun. 2000
Kaiga-1 Kaiga, Karnataka	PHWR	220	16 Nov. 2000
RAPS-4 Rawatbhata, Rajasthan	PHWR	220	23 Dec. 2000

TABLE IV–1. SUMMARY DATA FOR OPERATING REACTORS IN INDIA (cont.)

Unit location	Reactor type	Capacity (MW(e))	Startup of commercial operation
TAPS-4 Tarapur, Maharashtra	PHWR	540	12 Sep. 2005
TAPS-3 Tarapur, Maharashtra	PHWR	540	18 Aug. 2006
Kaiga-3 Kaiga, Karnataka	PHWR	220	6 May 2007

Note: BWR: boiling water reactor; PHWR: pressurized heavy water reactor.

TABLE IV–2. SUMMARY DATA FOR REACTORS UNDER CONSTRUCTION IN INDIA

Location	Capacity (MW(e)) and type	Targeted startup of commercial operation	
Kudankulam unit 2 Kudankulam, Tamil Nadu	1 × 1000 PWR	2014	
Rajasthan units 7 and 8 Rawatbhata, Rajasthan	2 × 700 PHWRs	Unit 7	2016
		Unit 8	2016
PFBR Kalpakkam, Tamil Nadu	500 FBR	2014	

Note: FBR: fast breeder reactor; PHWR: pressurized heavy water reactor; PWR: pressurized water reactor.

IV–2. EXPERIENCE WITH SMRs

IV–2.1. Design

The first PHWRs were set up with technical assistance from AECL. However, after the discontinuation of technical cooperation in 1974, the entire design effort has been indigenous. The improvements in design and the development of a standard 220 MW(e) design have been a result of indigenous efforts. The design was also scaled up to 540 MW(e), with improved reactor control features. India, therefore, has a comprehensive design capability of small and medium sized PHWRs.

IV–2.2. Construction period

All of the reactors have, so far, been set up on a twin unit basis, and the gestation period from the first pour of concrete to criticality for the first reactor of a twin unit project implemented in the past two decades is shown in Fig. IV–1.

In addition to the upgrades/design changes implemented in parallel with the construction, indigenous development of the equipment/components by local industry and available industrial infrastructure contributed to the high gestation period in the past. The construction of the reactors at Kaiga and Rawatbhata was proceeding according to schedule when the work had to be stopped for detailed re-engineering of the reactor dome, resulting in a delay of 40 months.

With the industry becoming mature, with completion of the design prior to commencement of the construction, with full use of the industrial infrastructure that has greatly improved over the years, with the introduction of the open top method of construction, with civil construction and equipment mounting works being performed in parallel, with project execution on the basis of large engineering/procurement/construction packages, with a three shift working schedule, and with the introduction of modern project management tools and electronic communication facilities, construction periods for the PHWRs have decreased. For example, criticality of Tarapur-4 was reached within 60 months after the first pour of concrete. The important milestones of this project were as follows:

— First pour of concrete: 8 March 2000.
— Release of vault for equipment mounting: 14 December 2001.
— Installation of the calandria and end shields: 3 May 2002.
— Installation of the feeder: 30 September 2003.
— Hot conditioning: 22 October 2004.
— First criticality: 6 March 2005.
— Synchronization to the grid: 4 June 2005.

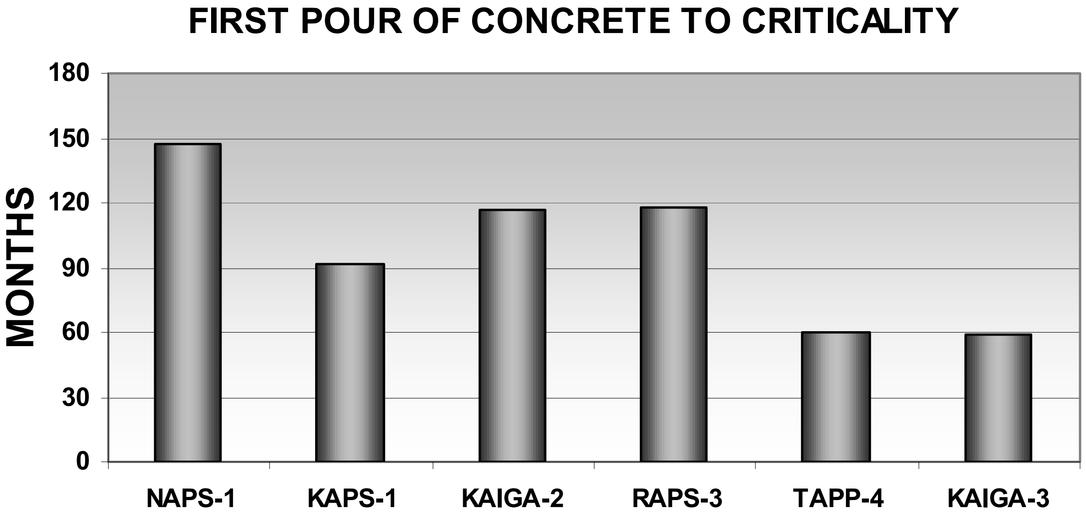

FIG. IV–1. Gestation period from the first pour of concrete to criticality.

IV–2.3. Operational experience — availability

Indian SMRs have been operated at a consistently high availability factor of about 90%, for many years (Fig. IV–2).

In terms of a key World Association of Nuclear Operators (WANO) performance indicator, the unit capability factor of Indian reactors was 89.3% in 2005, compared to the world median of 86.8%.

The operation of Indian SMRs at plant load factors of 90% has been demonstrated over a long period of time [IV–1] (Fig. IV–3).

IV–2.4. Operational experience — safety

Indian SMRs have a good safety record, with over 280 reactor-years of safe, accident free operation. In 280 reactor-years of operation, only five incidents (one of level 3 and four of level 2 on the International Nuclear and Radiological Event Scale (INES) have occurred, with no radiological consequences.

The Indian median for the WANO safety indicator, ‘safety system performance 1, 2 & 3’, which indicates the availability of standby safety systems, was better than the world median in 2005. Similarly, the median for another safety indicator, ‘industrial safety accident rate’, in India was better than the world median. Other safety indicators were close to the world median.

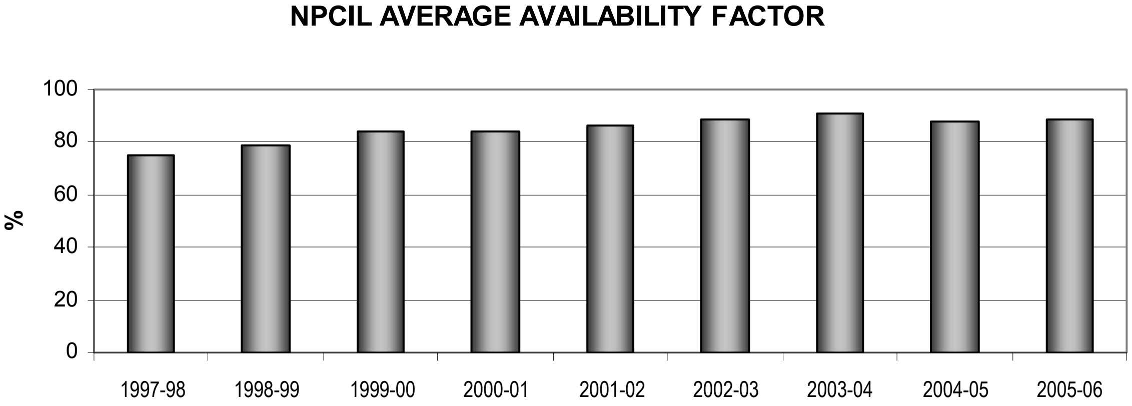

FIG. IV–2. Average availability factor of pressurized heavy water reactors operated in India. NPCIL: Nuclear Power Corporation of India Limited.

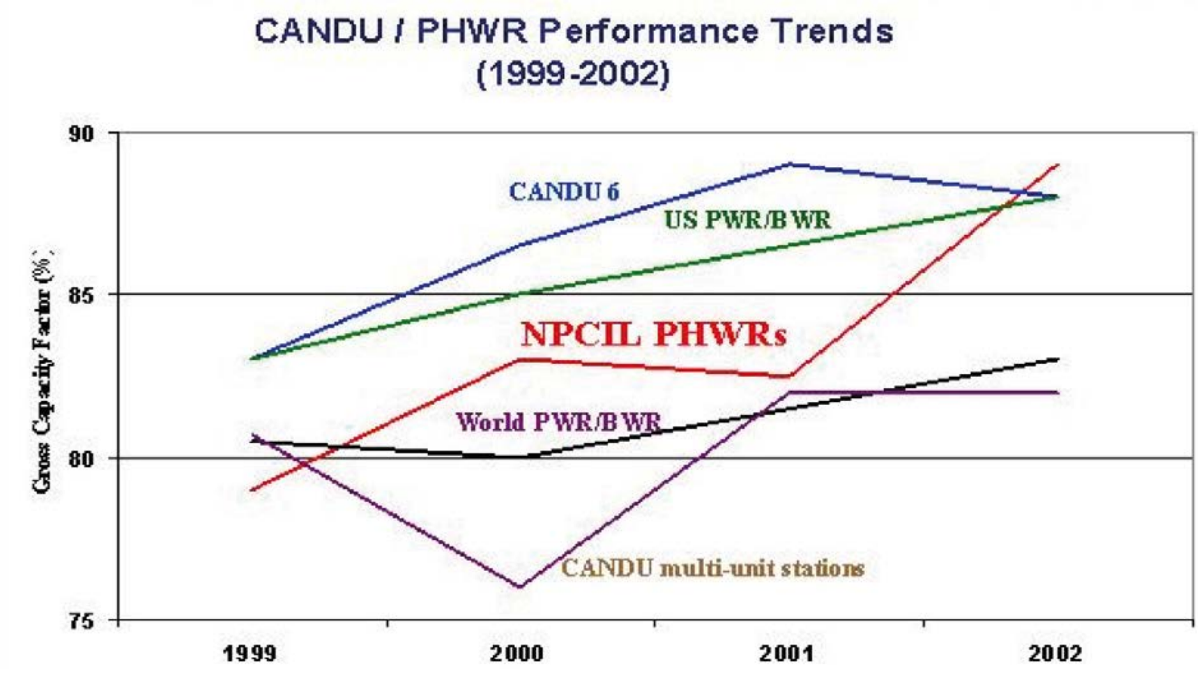

FIG. IV–3. Performance of pressurized heavy water reactors (PHWRs) compared with other reactors types [IV–1]. BWR: boiling water reactor; CANDU: Canada deuterium–uranium; NPCIL: Nuclear Power Corporation of India Limited; PWR: pressurized water reactor.

The Atomic Energy Regulatory Board (AERB), reporting to the Atomic Energy Commission is the top independent regulatory authority for nuclear power in the country. The dose limit to occupational workers as specified by the AERB, against the 50 mSv/a limit recommended by the International Commission on Radiological Protection, is 30 mSv/a (with a cumulative limit of 100 mSv over five consecutive years). The dose to the occupational workers has been well within the limit set by the AERB and international standards.

The dose to the environment has been a very small fraction of the limit prescribed by the AERB. Figure IV–4 illustrates the environmental dose from nuclear power stations over the past 10 years with regards to the regulatory limit and the background radiation due to natural causes such as cosmic rays and solar radiation.

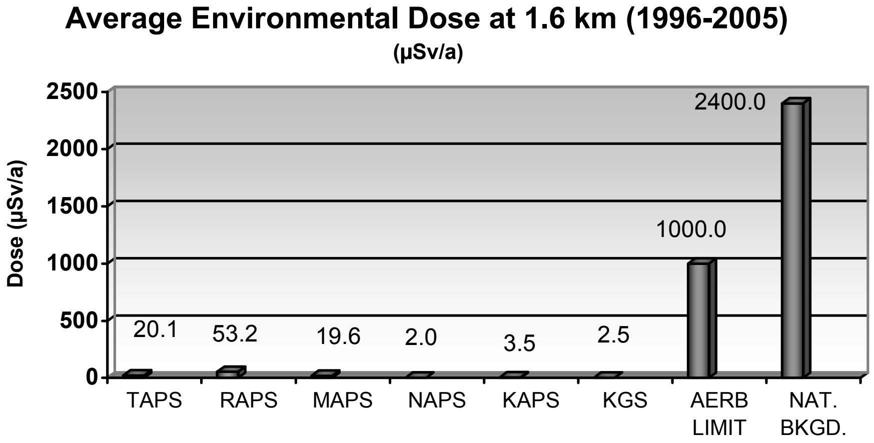

FIG. IV–4. Average environmental doses versus the Atomic Energy Regulatory Board (AERB) limit and the natural background (NAT. BKGD.).

IV–3. RENOVATION AND MODERNIZATION

India has extensive capabilities and experience in renovation and modernization, life extension and other in-core jobs for PHWRs. The coolant tubes of earlier PHWRs had a life of ten effective full power years. Coolant channel replacement has been carried out in six reactors (RAPS-2, MAPS-1&2, NAPS-1&2, KAPS-1). In addition to this, several safety upgrades and replacement of critical equipment/components have been carried out, leading to an extended life of the reactors. The feeders in the MAPS-1 primary heat transport system were replaced, for the first time in a PHWR in the world. Feeder replacement has also been completed for NAPS-1. The feeders of KAPS-1 and NAPS-2 will be replaced during the current coolant channel replacement job.

Several in-core jobs have been accomplished using innovative and cost effective solutions. They include repair of the overpressure relief device in an inaccessible area in the calandria of RAPS-1, the introduction of spargers in MAPS-1&2 moderator systems to solve the problem of a failed moderator inlet manifold, and the replacement of hair pin type steam generators.

IV–4. INDUSTRIAL INFRASTRUCTURE

The Indian position in the 1960s was different compared to other countries with nuclear power programmes that had an established industrial infrastructure owing to defence and aerospace activities. The efforts in India have been directed at building an indigenous industrial base that could support the stringent requirements of quality demanded by the nuclear industry. Heavy engineering industries for manufacture of large size electrical equipment, machine tools, forgings, castings and industrial plant and machinery have been set up in the country, and an augmentation of these facilities in respect of the machine tools and quality control equipment, as well as establishing clean room conditions required for nuclear components, was necessary. In respect of certain critical equipment, technical expertise has been obtained in the initial stages under technical assistance agreements to serve as a guide to develop satisfactory indigenous manufacturing under local conditions. The industries that have the basic capability to take up such jobs were chosen, and several measures were taken to develop the manufacturing technology suiting the Indian conditions. For conventional equipment, the approach was to choose the industries that were already supplying such equipment to the conventional thermal power sector and to meet the specific requirements by appropriate augmentation. Most of the components for NAPS were manufactured by Indian industries. When manufacturing of larger size nuclear components and other equipment for the 540 MW(e) PHWRs had to be undertaken, this could be readily taken up by the Indian industry because of the capability developed in the manufacturing of the 220 MW(e) PHWR components.

IV–5. EVOLUTION OF UNIT SIZE

The total installed capacity of the country in the mid-1960s was about 30 000 MW(e), equally shared between hydro and thermal power. As the average unit size was 100 MW(e), the grids were able to accommodate only small sizes, and a unit size of about 200 MW(e) was adopted for nuclear power reactors. Subsequently, the 220 MW(e) PHWR design was upgraded with concepts that could be adopted for larger size. The current maximum unit size in the country for coal fired power plants is 500 MW(e), and the 540 MW(e) PHWRs connected to the grid in 2005 and 2006 are, thus, the largest unit size nuclear reactors in the electrical system. With the interconnection of central and northern grids in India, synchronous operation of 88 000 MW(e) (about 80% of the country's capacity) became possible, and the grids can now accommodate larger size units. Consistent with developments of the electrical systems, the PHWRs to be set up in the future will be 700 MW(e). Additionally, 1000 MW(e) PWRs have already been constructed, under a contract with the Russian Federation.

With a view to using the full potential of the sites and the available infrastructure, new reactors have been set up at existing sites. The power stations, therefore, have a capacity that has been increased over a period of time. With the progressive completion of the projects under construction in 2013, the station capacity in MW(e) will grow (Table IV–3).

TABLE IV–3. SUMMARY DATA FOR FUTURE STATION CAPACITY (IN MW(e))

Station	Operation	Total
Kaiga	660 (3 × 220)	
Kakrapar	440	440
Kalpakkam	440	940
Kudankulam	2000	2000
Narora	440	440
Rawatbhata	740	1180
Tarapur	1400	1400

IV–6. CAPITAL COST OF CONSTRUCTION

The overnight cost of the first Indian reactors of 220 MW(e) set up in the 1960s was $1000/kW(e) (2006 prices). As has been the case the world over, the overnight cost increased over time with the incorporation of several advanced safety features and time overruns. The overnight cost of the later 220 MW(e) reactors ranged from $1300/kW(e) to $1500/kW(e) (2006 prices). This cost included the local infrastructure cost. The overnight cost of the 220 MW(e) PHWR works out to about $1200/kW(e), excluding the fuel and heavy water costs during commissioning and the cost of the land and infrastructure.

The overnight cost of the 540 MW(e) PHWRs set up at Tarapur was $1380/kW(e), at 2006 prices. The overnight cost of the 700 MW(e) PHWR to be set up in the near future is estimated to be lower, at $1170/kW(e), due to economies of scale and the benefit owing to the reactor output increasing from 540 to 700 MW(e) by permitting boiling in the channels, with only a marginal increase in the hardware cost.

IV–7. ELECTRICITY COST

In India, the bulk of the baseload generation comes from coal fired thermal power plants. The coal mines are located in the eastern part of the country. Nuclear power in the country has been competitive with coal based thermal power at distances of about 800 km from the coal pitheads. As there are several areas in the country that are away from the coal mines and where the haulage cost of the coal becomes prohibitive, nuclear power is an economical source of baseload generation in these areas.

The levelized unit electricity cost (LUEC) for a 220 MW(e) PHWR is estimated to be approximately \$37/MW·h at a 5% discount rate (2006 prices). The LUEC for the indigenous 700 MW(e) PHWRs has been estimated to be about \$33/MW·h at a 5% discount rate (2006 prices). These costs compare well with the estimated international prices of nuclear electricity for plants to be set up in the near future. In the Indian scenario, they are lower than those of coal and gas power plants at the 5% discount rate. The actual tariffs of nuclear power stations in the country range from \$20/MW·h in the case of the oldest stations, TAPS-1&2, to the maximum of \$65/MW·h in the case of Kaiga-1&2 (220 MW(e) PHWRs).

IV–8. FUTURE PLANS

A 700 MW(e) PHWR design, based on permitted limited coolant boiling in the 540 MW(e) reactor core, has been developed. The PHWRs to be set up in the future are planned to be of this unit size. Four units of 700 MW(e) PHWRs and four 500 MW(e) FBRs are planned to be set up by 2020, in addition to the reactors presently under construction. Initiatives of the Government of India open up the possibilities of setting up more nuclear power reactors based on imports. However, these are considered as additional ones to the indigenous programme, to enable large capacity addition in the near term. The long term objective of thorium utilization will include only PHWRs of 220 MW(e), 540 MW(e) and 700 MW(e), and 500 MW(e) FBRs.

IV–9. OFF-PEAK APPLICATIONS

The nuclear power reactors in the country have been operated as baseload stations. The current lack of reserve in the country and the general shortage in generating capacity has permitted operation at near full power throughout the day and all days of the year. However, with progressive implementation of the reforms in the power sector in India, and with the introduction of competitive bidding of power and the merit order dispatch (the generator with the highest tariff is required to reduce output first) followed by the establishment of load dispatch centres, nuclear power reactors may, in the future, have off-peak excess capacity. Utilization of this excess capacity in pumped storage schemes is being considered as one of the options for the future. However, this requires establishment of a national grid and the ability to transmit power over long distances at reasonable costs since the storage schemes are physically far from the nuclear power reactors.

A nuclear desalination demonstration plant was set up near the Madras Atomic Power Station (MAPS). The process (sea) water discharge from MAPS was made available for the reverse osmosis (RO) plant to avoid the requirement for a separate seawater intake system for desalination by the RO plant. In addition, MAPS also supplied part of the high pressure exhaust steam and a small quantity of the live steam to a multistage flash evaporation plant set up for seawater desalination. The potential of setting up large seawater desalination plants in the country using nuclear heat is immense. The vision of the Government provides for exploitation of this potential.

IV–10. EMERGENCY PLANNING ZONE

The emergency planning zone (EPZ) for reactors in India extends over a 16 km radius around the plant, in accordance with the regulatory (AERB) provisions. It consists of an exclusion zone of 1.5 km surrounding the power station where no habitation is permitted. This area is fenced or walled off, defining the boundary of the site. A sterilized zone, up to a distance of 5 km from the plant, where no new economic activity potentially leading to an increase in population beyond natural growth is permitted, is also established. The EPZ of a 16 km radius around the plant site is in the public domain, except for the exclusion and sterilized zones.

The establishment of an exclusion zone of 1.5 km involves the acquisition of about 1000 ha of land in the case of coastal sites and 1500 ha in the case of inland sites. This leads to a large number of affected persons who have to be displaced and rehabilitated. Reduction of the exclusion zone has the potential to reduce the pressure on land. This can be justified only in the context of improved safety features of new reactors.

The off-site emergency plans for the EPZ are well laid out and approved by the AERB. These are periodically tested involving local district administrative machinery. The feedback from these exercises is used to further improve the emergency response system.

No change in the EPZ is foreseen in the near future in respect of NPCIL power reactors. For next generation advanced reactors, the issue of the requirement and extent of the EPZ could be revisited, depending on the confidence of precluding those accidents that require emergency countermeasures.

IV–11. CONCLUSION

India started its nuclear power programme in the 1960s by importing technology and collaborating on its development in the initial phase, with the objective of making the programme self-reliant, consistent with the availability of industrial infrastructure in the country. In view of their low investment requirements, SMRs (in the Indian case, PHWRs), have contributed to acquiring the current level of maturity of Indian nuclear power. The power reactors have provided electricity at competitive rates, the safety performance has been good, and the accelerated growth of nuclear power is currently among a few realistic options for meeting the energy requirements of the country. The concept of exploiting the full potential of a site by incrementally building additional reactors at the same site (the Rajasthan site will have six smaller capacity reactors and two 700 MW(e) PHWRs) has resulted in a significant overall power station capacity. The trained manpower and technology acquired through SMRs now enables the country to undertake work on larger power reactors. India is in a unique position as one of the few countries in the world with a comprehensive capability in the siting, design, construction, operation, renovation and modernization, and plant life extension for SMRs (PHWRs), with an industrial infrastructure, as well as human resources, currently in place.

SMRs enable countries without a nuclear power programme to begin such a programme with relatively smaller investments. SMRs are suitable for countries with a relatively small electricity grid and an industrial infrastructure not suitable for large reactors.

REFERENCE TO ANNEX IV

[IV–1] COGNIZANT, Monthly Newsletter, Vol. 8, India (2003).

Annex V

FUTURE PERSPECTIVES FOR SMALL AND MEDIUM SIZED REACTORS IN INDIA

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V–1. INTRODUCTION

Innovative small and medium sized reactors (SMRs) have several features that are expected to affect their future development and deployment in India. These include the:

- Potential for simpler designs and reduced demands for human intervention, resulting in fewer potentially unsafe actions;
- Potential for construction close to population centres, due to enhanced safety;
- Potential of using the capability and capacity of local industries to enable their participation in the design and construction of such reactors, and high adaptability to the standardization and modular construction approach;
- Potential to achieve low upfront capital costs.

Future SMR concepts, employing increased use of passive safety features and capable of producing both electricity and high temperature process heat, may find application in specific regions of the country to supply both electricity and process heat, through distributed deployment.

The following sections describe future SMR design concepts meeting the above mentioned objectives, and highlight their projected economic competitiveness.

V–2. INNOVATIVE SMRs WITH POTENTIAL FOR CONSTRUCTION CLOSE TO POPULATION CENTRES

V–2.1. General observations

The global demand for energy is expected to increase manyfold over the next 50–100 years, driven in large part by population growth and the desire to improve the standard of living, especially in developing countries [V–1]. Many developing countries are targeting to meet the energy requirements of their ever increasing population through sustainable energy programmes, which also promote socioeconomic growth of the country by exploring innovative design characteristics of the energy producing option and giving priority to those options that would satisfy the economic growth requirements of the country in the long term. Moreover, reliable and affordable energy is crucial to the economic well being and security of all countries.

Electrical power plays a key role in the production of goods and services in almost all areas, including both the commercial and industrial sectors, and directly and significantly influences the lifestyle of citizens of a country. Populated areas of a typical country encompass several electricity consumers such as small, medium and large scale industries, commercial sectors, markets, agriculture, water supply, transportation requirements, health service providers, educational centres, telecommunication facilities, household appliances, street lighting, etc. The socioeconomic growth of any region inhabited by a large population is strongly influenced by the accessibility and availability of electrical power. This includes reliable assurance of the supply in addition to economic compatibility to the user. Industrial establishments involved in supporting the socioeconomic requirement of the society in the form of creating jobs and income and improved infrastructure give increased importance to reliable supply.

The sustainability of energy provision compels turning attention towards exploiting options and resources that will not hamper the interest of future generations, due to depletion of fossil based fuels, and deterioration of the environment due to emission related issues. The natural environment should not be exploited and degraded to meet the interest and pursuit of economic development. The present generation should not deprive future generations by indiscriminate usage of non-replenished fossil fuels to satisfy present requirements. Increased CO_2 and SO_2 emissions emanating from the massive use of fossil fuels from conventional fossil fuel fired plants pose the threats of climate change and the deterioration of global environmental conditions through high pollutant loading, which is a potential danger to the health status of citizens. The net reduction in environmental impacts could be substantial if cleaner power producing options were used. Moreover, swings in the market prices of coal, oil and gas make them high risk investments from the viewpoint of investors in a liberalized market, where uncertainty concerning the supply and price of fossil fuels is ever increasing, and is expected to change drastically in the future. Furthermore, if tax is levied for controlling pollution, then the cost of electricity generation using fossil fuels will further increase.

Energy projects are more capital intensive than projects in most other industries, involving large initial investments before production can begin. In many countries, domestic savings are the main source of capital for energy projects, and availability is mostly constrained in developing countries. The more the capital intensive an energy project, the more exposed it is to financial risks such as changes in interest rates and other possible events in the financial market. The higher the risk associated with an investment, the higher the cost of the capital, and the higher the return required by the investors and lenders. In addition to this, in many developing countries, the electricity grid infrastructure allows only smaller grid capacity increases compatible to the limited investment capacity; the preference is, therefore, for small electricity grids that favour SMRs over high capacity nuclear power plants. Moreover, small reactors would be flexible in power generation and their construction in series could offer incremental capacity addition through which the investments could be spread in time to reduce associated financial risk.

In this context, SMRs using innovative design concepts could play an important role in meeting the rapidly expanding world energy demand, consistent with the principle of sustainable development, i.e. meeting the requirements of current generations without compromising the ability of future generations to meet their requirements.

Activities on design and technology development for SMRs are ongoing in many countries, and most future SMR developments make use of innovative concepts in their designs [V–2]. These future reactors would target improvements in safety, and, once developed, could become the desirable option for sustainable generation of electricity in the country of deployment. Moreover, in order to play a meaningful role in the global energy supply in the foreseeable future, especially in developing countries, these innovative design concepts would also have to be economically competitive.

The technical safety objective of such reactors would be to take all reasonably practical measures to prevent severe plant conditions, and to mitigate their consequences, if they occur, including incidents of very low probability with the potential for large releases of radioactivity. This is essential to minimize radiological consequences to the public; even during such incidents, they should remain below the prescribed limits. The following describes future innovative SMR design concepts being developed in India.

V–2.2. Broad outline of a conceptual pressurized heavy water type innovative SMR

The nearer term conceptual innovative SMR under study in India is a pressure tube type, heavy water moderated, light water cooled reactor; it uses specific technologies pertaining to pressure tube and low pressure moderator based design. Later, it will be referred to as an innovative pressurized heavy water reactor. As it is the concept of the reactor being discussed, no finer technical specifications will be provided, except that the power output of the reactor falls in the range of a typical SMR [V–3, V–4].

The safety approach of the reactor is based on a combination of its inherent safety features and engineered passive safety systems, forming the required layers of the defence in depth concept. These distinguishing features are expected to provide significant enhancement in the safety of the reactor through minimization of operator intervention and elimination or reduction of dependence on active systems to fulfil the safety functions. Altogether, this is expected to contribute to a very low core damage frequency.

Typical design features leading to an increased safety for the conceptual SMR are given in Table V–1.

TABLE V–1. TYPICAL DESIGN FEATURES ENHANCING THE SAFETY OF INNOVATIVE PRESSURIZED HEAVY WATER TYPE SMRs

Safety function	Inherent safety features	Passive safety features and systems	Active safety systems
Prevention of fuel failure	Slightly negative void coefficient of reactivity; Low core power density; Negative fuel temperature coefficient of reactivity; Low excess reactivity; Large coolant inventory in the main coolant system to ensure reduced rate of temperature rise; Natural circulation driven heat removal during normal operation	Two independent, fast acting diverse shutdown systems; Passive injection of high pressure and low pressure ECCS directly into fuel cluster during postulated event, such as LOCA; Multiple redundant passive ECCS trains	Continuous monitoring of plant states; Automated instrumentation and control system for reactor regulation and plant control
Prevention of pressure boundary failure	Cold moderator surrounding the fuel channels, which can serve as a heat sink; Water filled reactor vault; Availability of large inventory of water in the overhead pool; Selection of material, design, fabrication and inspection as per code, and provision for in-service inspection; Feasibility of incorporation of leak before break concept	Passive reactor shutdown system, operated due to increase in coolant pressure, serves as a backup to the two independent fast acting shutdown systems; Passive decay heat removal system using coolers immersed in overhead water pool; Overpressure protection by safety relief system	Main condenser steam dumping system
Elimination of high pressure core melt ejection	Low pressure calandria (reactor vessel) surrounded by cold water of moderator and reactor vault	Flooding of reactor cavity following LOCA	Long term circulation and cooling of flooded water in the cavity, following LOCA
Maintaining containment integrity	Design of containment to withstand pressure and temperature generated during largest break in main circulation system	Passive containment coolers for vapour suppression, and heat removal systems to minimize pressurization and heating	
Control of releases outside the containment	Double containment	Limiting radioactive releases by passive containment isolation and filtering of potential leakages, and passive cooling of containment	Mechanical dampers to isolate containment; Primary containment cleanup system and primary containment controlled discharge system to minimize releases of radioactivity after postulated beyond design basis accidents

Note: ECCS: emergency core cooling system; LOCA: loss of coolant accident; SMR: small and medium sized reactor.

V–2.3. Main design features of innovative pressurized heavy water type SMRs leading to reduction of capital costs

Several economic benefits can be expected from an innovative SMR, in respect of the growing energy demand. Large portions of the population would benefit from a reliable cleaner energy source that provides access to electricity, potable water via desalination, heating requirements, etc. The objective of achieving reduced upfront capital cost is critical for the economic attractiveness of SMRs in the country of deployment. It is well known that the construction cost per unit of power output is observed to be higher for power plants designed to produce low power compared to high power output plants. To cope with this, an innovative SMR should be designed for higher simplicity and increased reliance on passive systems. The following features could result in reduced capital costs of the reactor.

The cooling of the reactor core under normal operating conditions takes place through natural circulation of the coolant. The use of natural circulation for core cooling, and the associated elimination of expensive nuclear grade circulation pumps and control and instrumentation would have favourable impacts on reducing the capital cost and operation and maintenance (O&M) requirements of the innovative SMR. This would also simplify the piping and the layout of the main heat transport system. The steam produced by the reactor is separated from the steam water mixture by gravity in steam drums, which are comparatively easy to design and manufacture and which would cost less than huge complex steam generators. Leakage monitoring and in-service inspection, etc., required in the case of a conventional steam generator, are eliminated, with corresponding savings in the costs. Expensive steam dryers are also eliminated.

The coolant used is light water instead of heavy water, and this eliminates the investment in costly heavy water production. The heavy water losses are minimized, as the heavy water is used only in the low pressure moderator system. This also reduces the investment in heavy water recovery and tritium management systems, leading to corresponding cost savings.

The reactor is provided with a passive cooling arrangement for reactor core cooling during shutdown by using passive isolation condensers immersed in a pool of water located in an overhead tank. This system eliminates the use of an active shutdown cooling system and nuclear grade equipment, such as heat exchangers, pumps, associated piping, and instrumentation and control. The O&M expenses and investment required in the active shutdown cooling system are, thus, eliminated.

The reactor uses pressure tube technology, and houses fuel bundles inside the pressure tubes. The pressure tubes are surrounded by a low pressure moderator contained in a calandria vessel. The use of an expensive thick pressure vessel is eliminated by incorporating pressure tube technology and a low pressure calandria vessel of simple design that is easily adaptable to shop fabrication, with the potential for achieving higher manufacturing quality through mass production and design standardization.

The design life of all non-replaceable structures and components (including the calandria vessel, the end shields, the major piping and concrete structures) is 100 years. All components and equipment of shorter design life can be easily replaced during routine shutdowns. For example, the pressure tubes of the innovative SMR can be easily replaced, enhancing the plant lifetime. This also eliminates the requirement for long shutdown periods for replacement of the coolant channel.

The reactor is provided with a direct cycle moderator heat recovery system to achieve better thermodynamic efficiency of the plant. The moderator heat is used to heat the feedwater and, therefore, the overall plant efficiency is improved.

The reactor uses high burnup fuel, resulting in lower fuel consumption and in savings in the fuel handling and reprocessing costs. On-line refuelling, reprocessing and recycling of both fissile and fertile materials are foreseen to facilitate low consumption of fuel materials.

V–2.4. Other features of innovative SMRs contributing to improved economy

The basic siting criterion for nuclear reactors is to ensure that the site–installation interactions, potentially arising out of severe plant conditions, do not introduce radiological or other risks of unacceptable magnitude. To protect the public in the unlikely event of a severe accident, emergency preparedness planning and evacuation measures are provided for in nuclear power plant projects. Emergency preparedness planning is aimed at protecting, evacuating and sheltering of the public at large, in the case of an unlikely event due to severe plant conditions in the reactor. The plant operator or utility owner has to fulfil this objective through appropriate planning and associated administrative set-up, incurring expenses at each stage, and has to periodically run mock exercises to check the adequacy of the emergency planning operations.

The safety criteria imposed by a regulatory authority require the utility owner to build conventional nuclear reactors with the stipulated protective and sterile zone around the plant [V–5, V–6]. Considering the requirement of large areas, in most cases, the owners are likely to select low cost land located far away from population and load centres. Site selection offers little choices in these circumstances, as potential burdens such as rehabilitation of displaced people, pacifying objections of local people, extra efforts required for improvement of the infrastructure, such as construction of roads and bridges, provision of extra water supplies, provision of educational and medical facilities and housing, would always need to be addressed and planned.

The use of improved design characteristics contributing to various levels of defence in depth is expected to facilitate construction of the innovative SMR close to population centres owing to the anticipated lower core damage frequency and lower source term. A nuclear power plant location near population centres would also serve as a source of infrastructure evolution in the surrounding areas, for example, achieved through the development of better roads and transportation, creation of work-places and other related activities.

V–2.4.1. Advantages of a simplified electricity grid system owing to the potential of deployment near consumption points

Conventionally, in many countries, electricity is supplied to the consumer points through complex electrical grid systems from central power plants located far away from the consumer points. Such an approach often suffers from many disadvantages, such as increased transmission and distribution losses, inflexibility in operation, oversized electrical equipment, frequent faults in the grids resulting in interruptions in the power supply, and a higher cost of transmission and distribution. Many industrial and vital services require an uninterrupted power supply. In view of the above mentioned issues, it may be preferable to have the energy producing centres near population and load centres. The deployment of environmentally friendly power plants in proximity to a populated zone facilitates smaller grid systems for handling electricity distribution to consumer points, with improved availability and reliability of power supply. These trends are more suitable for developing countries due to their low incremental load growth. Cost effective smaller grid systems avoid many of the above mentioned disadvantages of centrally located power plants and intensify the effort to invest in such options. A smaller grid system has the following salient features:

- Proximity to the load centre;
- Grids can be localized to cities;
- Reduced transmission and distribution losses;
- Simpler transmission and distribution grid systems;
- Lower grid costs;
- Improved reliability of supply due to multiple smaller units located at, or near, the consumer point, as compared to a single large centralized power plant;
- Associated infrastructure development and improvement in living conditions;
- More potential for attracting investments due to the low total cost and reduced risk.

The above mentioned factors would favour the economics of innovative SMRs when the latter are deployed near customer load points. Apart from this, other energy products from the reactor, such as heat for heating systems or desalinated water, could be utilized in a cost effective manner, with minimum infrastructure and minimum losses, when the reactor is located near the user.

V–2.4.2. Reduction in capital costs via sharing of common facilities

For further reductions of capital costs, another domain could be explored; this is the sharing of on-site facilities, such as service buildings, fuel storage and handling facilities, switchyards, waste management facilities, intake and outfall structures, station auxiliary and backup control buildings, stacks and administrative buildings. For example, two or more reactor units could be constructed side by side, sharing these facilities. This would reduce the capital cost further, and would also simplify the layout of the power station. Generally, the costs of these common facilities constitutes a considerable fraction of the capital cost of the reactor. Sharing of the facilities is also expected to reduce O&M costs, due to centralization.

When a number of reactors are constructed in sequence at the same site, cost advantages arising from standardization, modular construction, learning from construction activity, shop fabrication of components, use of electricity from completed units for construction activities of subsequent plants, etc. become apparent. During operation, scenarios such as total station blackout could be avoided through availability of power from the other units connected to the grid, thus improving the safety and reliability (security) of the power supply.

Obtaining a regulatory certificate for the initial standard design may be expensive and time consuming, but once this is accomplished, there would be no delays before going into commercial operation, as all the procedures and equipment would be standardized, and the regulatory requirements would be the same for subsequent plants. A nuclear power plant, notwithstanding its high upfront capital investment, has lower running costs [V–7]. Altogether, the above mentioned features could secure an attractive economic and investment profile for innovative SMRs.

V–2.4.3. Flexibility for siting near populated areas

Land cost in populated urban areas is rising due to the development spree undertaken by various governmental bodies and housing societies. Therefore, optimum utilization of land assets requires much attention. More effective land use planning is critical to enhance access to urban services for improving quality of life. It is desirable to have power plants giving maximum power per unit area employed to locate it. Conventional fossil fuel power plants occupy large areas, when all the associated ancillaries, such as storage of fuel and ash disposal, are taken into consideration. Owing to the high cost of land in populated areas, the land cost will frequently be an additional burden on the capital outlay of such plants. For this reason, conventional nuclear power plants become expensive to locate near populated areas with high land costs — this would require a large protective zone around the plant; on some occasions, due to public opinion or policy reasons, land itself may not be available. The funds required to buy such costly land may sometimes run into unrealistic investment requirements.

One of the expected outcomes of a high safety level of the innovative SMR is that it may be possible to construct it near populated zones due to its expected low core damage frequency and source term. It is also expected that the land area requirements may decrease for such reactors, compared to conventional reactors, and that this would favour SMR construction near populated areas, for purely economic reasons. In the future, in the case of scarcity of suitable land, and when the cost of land far away from the populated areas would also become relatively expensive, the reduced land area requirements of innovative SMRs could play a major role in capital cost reduction.

Coal based power plants producing power output equivalent to an SMR require considerable land areas, including allied requirements, such as fuel storage and ash disposal. It is expected that several innovative SMRs could be constructed in the same area, enhancing the energy output per land area. Added to this, the burden on environment and society from pollutants could also be eliminated. Building a number of units of innovative SMRs at the same site would be more effective than building one or two units of fossil fuelled power plants in areas where a large population density and industrial infrastructure warrant a high magnitude of electricity generation capacity.

V–2.4.4. Non-electrical energy products and associated benefits

In addition to electricity, the reactor could also meet the requirements in non-electrical energy products, such as potable water, heat for district heating and process heat for industrial applications.

Potable water

Water is essential for humans, animals and agricultural products, and the demand for water is increasing. Improving access to water and sanitation has been cited as one of the effective means of alleviating human distress in highly populated areas. It was estimated that one fifth of the world's population does not have access to clean potable water, and this results in a massive number of illnesses and deaths every day due to water related diseases [V–8]. In the future, this situation is going to become severe because of population growth, commercialization and industrialization, especially in arid regions. It is expected that by 2025, 33% of the world's population will live in countries or regions without adequately clean water unless special means, such as desalination plants, are implemented [V–9].

In this regard, waste heat from an innovative SMR could be used to produce potable water and meet the water requirements of highly populated areas, without the economic penalty of water transport for long distances.

Heat for district heating

District heating systems use hot water or steam for heating. Steam extracted from low and high pressure turbines of a power circuit could meet the baseload and peak heat load demand, respectively. Since the sources of heat need to be located near the consumer points, the heat loss in the distribution system would be considerably reduced when an innovative SMR is used as a heat source. Generally, in district heating networks, pumps push the heated water through the pipelines to reach the buildings. The investment in the pipeline network and infrastructure would be reduced with SMRs because of the shorter distances involved.

Heat for industrial process heat applications

Applications of process heat may include:

- Food processing;
- Paper industry;
- Chemical industry;
- Petroleum and coal processing;
- Primary metal industries.

Industrial heating load requirements are usually steady and, therefore, nuclear power may be well suited to this application. As in the case of district heating, nearness of a nuclear power station to the process application is also vital, and the innovative SMR concept suits this requirement.

V–2.5. Potential for enhanced participation of local industries

As has been discussed above, future innovative SMRs have the potential to become an important part of energy programmes of both developed and developing countries [V–2, V–4]. The population and standard of living in developing countries are always increasing. Electricity demand is outpacing supply growth. Under the policy objectives of energy efficiency and environmental protection, the new policy paradigm of sustainable development has become the driving force behind the shift towards energy programmes supporting the use of cleaner energy, more efficient production technologies and more integrated process approaches. A cleaner sustainable energy source from innovative SMRs suiting the economic status of countries, and with added safety, may become relevant to this scenario. Although electricity and potable water and heat are the primary evident products of benefit from such reactors, several other multidimensional developmental aspects would be connected with the deployment of SMRs on a large scale, and they cannot be neglected.

The hallmark of sustainable energy programmes of countries aimed at meeting targets of their energy requirements are the availability of a pool of skilled labour, the existence of specialized suppliers for raw materials, equipment, components and machinery, and the availability and support of ancillary industries capable of delivering the goods required for the energy sources at an economic scale, commensurate with the overall cost burden of the energy programme. Realization of this objective will ultimately lead to the sovereignty of the energy programme undertaken by the country. It would also provide society with more jobs and income earning opportunities, and will lead to many socioeconomic advantages, such as increased service sector and assistance in poverty alleviation. A key solution to accelerate the industrialization of any country is urgent action in the field of industrial infrastructure development for the production of structures, equipment and components.

Efforts have to be made to develop local capabilities in technical skills, infrastructure and technology for countries with limited potential in these areas. Large capacity nuclear power plants require high capital investment, most of the time exceeding the financial capacity of developing countries, and, added to this, construction of large capacity nuclear power plants requires huge components and structures that are beyond the scope of the industrial capabilities of many developing countries. Therefore, SMRs requiring components of a smaller size and lesser design complexity may be better suited to the set-up and development of local industries in developing countries.

V–2.6. Benefits of local industrial participation in developing countries

SMR designs with the potential for promoting local industrial participation would enhance the growth prospects of the country through multidimensional advantages. Supervision, quality control, inspection, timely delivery of items, timely corrective actions for any defect of the designed and produced items, transportability, etc. could become easier when local industries are involved in the manufacturing of components for nuclear power plants. The above mentioned aspects tend to reduce the overall capital cost of the SMR planned to be deployed in the country of interest.

Lack of industrial development has resulted in living standards in developing countries being lower than in developed countries. In this respect, there is a special demand for policies and mechanisms that favour developing indigenous capabilities to solve energy problems in developing countries. Concepts of the innovative SMRs should preferably be compatible with the available capacity and capability of infrastructure and skilled labour resources in developing countries, which would then help set up and develop local industries. As an example, Table V–2 explains how this objective can be met with the conceptual innovative pressurized heavy water type SMR described earlier.

TABLE V–2. CHARACTERISTICS OF INNOVATIVE PRESSURIZED HEAVY WATER TYPE SMRs

System/parameter	Characteristics
Reactor technology used	Pressure tube type, light water cooled, heavy water moderated reactor
Mode of primary heat transport circulation	Natural circulation, no pump required
Available design power range	In the range applicable for a typical SMR
Other features	Use of passive safety features to meet defence in depth requirements, minimum operator action, enhanced reliability, higher capacity factor ~90%

Note: SMR: small and medium sized reactor.

A typical innovative SMR of the type mentioned above has many structures, systems and components that could be engineered and manufactured within local industrial infrastructure programmes in developing countries, owing to the quantity and size of such equipment items. For instance, the reactor has a simpler design compared to conventional vessel type reactors. Many of its components could easily be standardized and manufactured by smaller industries to the level of precision demanded by the reactor owner. The prospects for socioeconomic growth associated with the deployment of such reactors in developing countries could be bright and multiple at each stage of the programme, starting from the front end fuel cycle, through construction of the reactor, commissioning and testing periods, operation of the reactor, and ending with the back end fuel cycle. All of these stages would have a predominant role to play in national industrial development. The fuel cycle related activities could be outsourced, if the country does not have natural uranium. The nuclear infrastructure could be quickly enhanced further to facilitate more deployments of similar innovative SMRs through the feedback and technological experience gained.

V–2.7. Features of innovative pressurized heavy water type SMRs facilitating involvement of local industries

In the innovative pressurized heavy water SMR considered as an example, the expensive, complicated, large components are replaced by simpler components of smaller dimensions and simpler designs. A large pressure vessel is eliminated via the use of pressure tube technology. Today, pressure vessels are built in a few advanced countries, and then transported around the world. Complications related to timely placement of orders to these few vendors are avoided if the pressure tube design is used. Pressure tubes are much simpler to fabricate and can be easily standardized for shop production, leading to savings in their cost. Huge steam generators with complicated internal layouts are substituted by steam drums of simpler design. In addition, prefabrication of modules can be planned and extensively used to expedite the construction of pressurized heavy water type SMRs.

Many of the components and the hardware (including pumps, heat exchangers, nuclear fuel, control rods and some internal reactor components, as well as most balance of plant equipment) for this reactor can be produced in the country of deployment through development and enhancement of local industrial units. Whenever the large components (turbogenerators, diesel generator sets, condensers, etc.) are difficult to design and manufacture within the scope of the local industrial infrastructure of the country, there exists the possibility of outsourcing these items, based on competitive offers of the outsourced manufacturers. Alternatively, developing countries with skilled manpower and infrastructure for manufacturing can obtain design descriptions and licences to manufacture these specialized items. This would enhance competition among suppliers for the delivery of these equipment items.

The advent of computer aided drawing and design has largely contributed to the improvement in the construction sequence of nuclear reactors, by eliminating several bottlenecks and delays previously observed during construction phases. Computer aided design and engineering software packages have enabled the development of complex and sophisticated civil and structural models with ease, reducing the burden of making hundreds of individual drawings and physical models, and have improved the visualization of the entire layout and plant structure. These developments could be exploited for the benefit of working out the schedules, the design drawings and the cost estimates via participation of local industrial firms. The preparation of a layout before startup of construction also results in savings of valuable time and costs due to the pre-detection of possible clashes, interferences, etc. at the drawing stage rather than at construction, when costly modifications would remain the only solution.

While planning for nuclear power plant construction, it would always be ideal to locate manufacturing facilities near the nuclear power plant. Manufacturing facilities could be located with consideration of anticipated location of future power plants, to pave the way for a constructive, competitive environment, potentially resulting in a reduction of costs and as a reward to the companies and technical staff producing the components. The enabling features of the innovative SMR concept considered in this annex are summarized in Table V–3.

TABLE V–3. ENABLING FEATURES OF PHWR SMRs FOR DOMESTIC PARTICIPATION AND INDUSTRIAL GROWTH

Item	Feature
Shop fabricated calandria, coolant channel assemblies and calandria tubes	Use of low pressure calandria for the moderator and for housing of coolant channels eliminates the requirement to produce a thick walled reactor pressure vessel, which is associated with operations such as forging, machining, welding and stress relief, or with outsourcing of such a production when relevant capability is not available within the country Expensive thick walled reactor pressure vessels are replaced by compact, thin walled calandria and easily producible pressure tubes of designs suited to shop fabrication facilities of small and medium sized industries; these can easily be standardized and can be produced in large numbers for a series of reactors, taking advantage of the cost reduction achieved through standardization
Substitution of steam generators with steam drums of simple design	Large and expensive steam generators are replaced by simpler steam drums; production of complex forged subshells (including welding), tube sheets, internal tubing (including welding), support, and the inspection requirements to meet stringent leaktightness are eliminated High potential to master indigenous production of steam drums; forged subshells, if required, may be outsourced to external suppliers
End shields of moderate size Control rod drive mechanisms	Flexibility in fabrication could be achieved through standardization and use of the same parts in similar SMRs planned to be constructed in series

TABLE V–3. ENABLING FEATURES OF PHWR SMRs FOR DOMESTIC PARTICIPATION AND INDUSTRIAL GROWTH (cont.)

Item	Feature
Reactor primary coolant system piping Downcomers, inlet header and feeder pipes, and tail pipes	Piping and required supports can be shop fabricated in modules and then assembled at the site; the natural circulation driven cooling design simplifies the primary coolant system by eliminating pumps, valves and associated complex control and power supply units and instrumentation, etc.
Construction of containment and civil structures	Technologies for pre-stressed and reinforced containment shells and associated civil structures are, in general, available in developing countries

Note: PHWR: pressurized heavy water reactor; SMR: small and medium sized reactor.

In addition, many items of the equipment and site work required for the innovative SMRs are similar to those for non-nuclear power stations, petrochemical and other industrial facilities. Thus, experience from these non-nuclear projects could be used in local industrial set-ups.

V–2.8. Construction craft labour, materials and equipment

Construction activity generates many job opportunities, giving the opportunity for better prospects and living conditions to many people.

V–2.8.1. Craft labour requirements

Skilled manpower expected to be involved for the innovative SMRs discussed above include [V–10]:

- Site engineers;
- Pipe fitters;
- Welders to meet industry code requirements;
- Quality surveillance inspectors;
- Human resource managers;
- Machinists;
- Millwright technicians and fitters;
- Electricians/instrument technicians;
- Foremen;
- Sheet metal workers;
- Iron workers;
- Insulators;
- Labourers;
- Masons;
- Carpenters;
- Painters;
- Truckers.

V–2.8.2. Other on-site labour requirements

In addition to the above mentioned qualifications, other on-site labour specialties are required [V–10]:

- Craft supervisors;
- Site indirect labourers;
- Quality control inspectors;
- Nuclear steam supply system vendors and subcontractor staff;

- Engineering procurement construction contractor managers, engineers and schedulers;
- Owner’s O&M staff;
- Supervisors.

V–2.8.3. Bulk materials for construction

Bulk materials required for reactor construction [V–10] include the following:

- Raw materials for concrete work, such as cement, sand and coarse aggregate;
- Reinforcing steel and embedded parts;
- Steel, miscellaneous steel and decking;
- Large bore pipes;
- Small bore pipes;
- Cable trays;
- Ducting;
- Conduit;
- Power cables;
- Control wires;
- Process and instrument tubing.

All of these large volume materials can be readily produced in local industries and/or the corresponding industries can be set up.

V–2.8.4. Equipment

Equipment items that directly or indirectly influence the local industrial participation are:

- Heat exchangers and feedwater heaters;
- Control valves and pressure relief/safety valves;
- Instrumentation and control, pneumatic and digital based instrumentation;
- Tanks for storage of fluids;
- Moisture separator reheaters;
- Electrical and control panels;
- Various pumps;
- Pressure gauges, temperature gauges and transmitters.

V–2.8.5. Electrical equipment

Electrical equipment includes:

- Switch gear panels;
- Motor control centres;
- Direct current uninterruptible power supply systems;
- Alternating current uninterruptible power supply systems;
- Diesel generators;
- Transformers.

V–2.9. Enhancement of local participation through modular construction

Modular fabrication has become a common construction technique in many industries. A module is defined as a factory or workshop fabricated assembly consisting of structural elements, equipment and other items such as piping, valves, tubing, conduit, cable trays, reinforcing bar mats, instrument racks, electrical panels, supports, ducting, access platforms, ladders and stairs. Modules can be fabricated, assembled and tested at workshops to minimize activities at the plant site.

Modularization allows mechanical erection or electrical installation to be carried out at off-site factories/workshops in parallel with civil works, thus reducing site congestion and improving accessibility for personnel and materials, especially in the containment building; it also allows for a significant reduction of the schedule. This technique, which provides for fabrication in the shop rather than in the field, favours local industry involvement and also reduces the scope and minimizes the duration of the construction schedule.

The cost effectiveness and efficiency of the construction of a nuclear power plant play a major role in reducing the gestation period and cost through improvements in the quality of construction. Standardized design and construction through modular units, as well as the participation of local industries, reduce the capital cost of such innovative reactors. Parallel civil construction and equipment erection activities would speed up construction and reduce the gestation period.

Another important aspect of standardized serial construction is that construction crews become specialized to the extent that they can easily troubleshoot plant construction activities; they know exactly what to do, where to look for trouble spots, etc. due to experience gained from several identical plants.

Other advantages of modular shop fabrication are given below.

Enhanced productivity: Owing to the better working environment created by a well organized supply chain, improved supervision and indoor working conditions, labour productivity increases.

Reduction in labour costs: Generally, field labour costs are higher than shop labour costs. This results in a reduction of labour costs and production duration.

Reduced space requirement for installation: Installing modules that have almost been completed in shops requires less workers at a site, which is also an advantage when space is limited.

Improved quality control: Quality control standards can be better assured to improve standards in the shop fabrication environment compared to site construction. Owing to the medium size of the reactor, many of the systems can be adapted to modular construction in local industrial set-ups, and can be easily transported to the site for installation.

Modularization can be applied in the following three areas.

Mechanical modules: Mechanical equipment, such as heat exchangers, pumps and associated piping of process systems, can be installed on a common structural frame, complete with interconnecting piping, valves, instruments, wiring, etc. As an example, for the innovative pressurized heavy water type SMR, the process systems, such as the moderator system, the calandria vault cooling system, the end shield cooling system, the process water system and the fire water system, can be made in smaller modular units.

Electrical modules: Electrical equipment can be assembled on a common structural frame. Larger structural and equipment modules could be field assembled from multiple submodules manufactured by local industries.

Instrumentation modules: Control panels with many instruments can be assembled and tested in the shop; at the site, they would just be connected to the desired system circuits.

V–3. INNOVATIVE SMRs WITH POTENTIAL TO MEET THE REQUIREMENTS OF SPECIAL REGIONS OR SPECIAL APPLICATIONS

V–3.1. General observations

At present, the global demand for energy is increasing continuously; this trend is seen in developing countries where the per capita consumption of energy is only a small fraction of that in industrialized countries. As mentioned previously, one of the critical elements in sustainable economic development and improvement of life quality in a developing country is the reliable supply of electricity at an affordable rate. In many areas in developing countries, shortages of electricity supply are found to be due to lack of investment in the infrastructure that would allow reaching the populations living in remote places. Centralized grid systems appear too expensive; in addition, terrain constraints exist in some areas. Quite often, such areas are isolated from transportation routes due to hilly or desert terrain, rivers, swamps, etc. Remote locations often suffer from poverty caused by the lack of energy supply for producing goods, and productive time in such areas is substantially spent looking for fuel to meet housing requirements such as for cooking and to provide light. The use of traditional fuels, e.g. firewood or charcoal, ends up as a loss of time that could otherwise be spent on productive labour, and also results in deterioration of forests and in ill health.

Agriculture serves as a principal source of the livelihood of poor people in remote areas, and the lack of an energy supply deprives them of the option to perform irrigation during the dry spell, which leads to poverty and hunger. Under these circumstances, power generating equipment has top priority for developing countries. However, investments for the financing of large capacity electricity generating units, including the associated distribution and transmission costs, are a major challenge for such countries. Efforts for ensuring the economical supply of electricity to a large number of the population in remote areas have become a priority among many developing countries, in view of the increasing standard of living and the ever increasing demand for energy.

Developing countries will constitute 86% of the total world population by 2030 [V–11]. The bulk of the population in developing countries lives in rural areas. Most of the households in rural areas use traditional energy technologies that are, in general, very inefficient, and contribute to health hazards and pollution. To meet the minimum standard of living, an energy consumption of 8–10 GJ per capita per year is required for the rural population [V–11]. This figure will reach 9.5–12 GJ if a conversion efficiency of 85% is considered for household appliances.

Apart from the increase in the energy demand for services such as water supply, health care and education, productive activities, such as agriculture and small scale cottage industries, also require energy inputs. Typical rural electricity applications include:

— Activities for crop processing and animal husbandry;
— Electrification for household and street lighting;
— Energy for income generating activities;
— Lighting, fans, water supply and operation of the equipment required for educational institutions;
— Water pumping for the supply from overhead tanks;
— Health centre services (communications, refrigeration for medicines, lighting, disinfection, washing);
— Power for telecommunications.

Even in developed countries with a scattered population density, the availability of self-sufficient economical energy sources may be very important to meet local energy demands. The requirements for such sources are defined by the demographic situation, as well as by the natural resources and climate in the region. In addition to electricity, isolated places may require energy sources for heating during the winter season and for production of water for drinking and sanitation all year round. There are developing areas isolated from the mainland that require energy for local development. Initial energy demands for such areas are not enormous, and it would be uneconomical to build large power plants to meet such demands. Instead, distributed small power packs that are efficient, cost effective and environmentally friendly could solve the problem in a more competitive and sustainable manner.

Several electricity generation options are suitable for use in rural areas, depending on the local skills and natural resources available in the country. Internal combustion engines, photovoltaic electricity generation from solar energy, diesel generators, wind mills and microhydro plants should be mentioned in this respect. Some are attractive from the cleaner energy perspective; however, some offer intermittent energy production characteristics, often depending on climatic conditions. Options such as diesel generators may suffer from high fuel costs and high transport and maintenance costs in addition to being non-replenishable and causing pollution concerns. Environmental issues have prominence due to concerns related to the effect of greenhouse gas emissions and climate change, and the requirement for clean sources of energy should be put on the agenda. The technologies to meet these requirements need to be competitive.

The idea of a sustainable energy supply programme requires more attention with regards to the tapping of unexploited features of nuclear energy in smaller power packs that are affordable and cater to segments of the population in scattered places such as islands and hilly areas that are far away from the main electricity grid service systems.

The distributed generation of electricity is one possible alternative to the traditional approach to improving access to electricity. Small nuclear reactors can be designed to supply energy for many years without on-site refuelling, unlike thermal energy sources that require a continuous feed of fuel. A system of distributed smaller nuclear power packs to meet the energy requirements of isolated areas would be capable of advancing regional economic growth in an efficient, demand oriented and environmentally sound manner, contributing to the improved living standards of local populations.

The concept of a nuclear power pack for the generation of electricity and the production of high temperature processes, capable of operation without on-site refuelling for 15–20 years, is considered in India as a future perspective for the sustainable and economic production of energy in areas that cannot benefit from the deployment of large capacity plants. Such nuclear reactors would be most suitable for meeting the energy requirements of a scattered population living in remote places that is not served by the main grid systems, through distributed deployment. In addition to electricity, the power pack could also produce heat for district heating or process heat applications and desalinated water. In the future, if hydrogen becomes the energy carrier, its production using the heat produced by a small nuclear power pack sited close to the hydrogen production plant would be possible. The transport cost of hydrogen could be eliminated or minimized in such a case.

V–3.2 Multipurpose nuclear power packs without on-site refuelling

As in the case of the nearer term innovative pressurized heavy water SMR discussed earlier, the concept of a nuclear power pack without on-site refuelling is discussed here from the viewpoint of benefits that such reactors could potentially offer to their users. No detailed technical specifications for such reactors will be provided, except that the power output of the reactor falls in the range of a typical SMR [V–3, V–4].

V–3.2.1. Energy products of the candidate multipurpose nuclear reactor

A multipurpose small nuclear pack is expected to meet the objectives specified below.

Electricity

The power pack could satisfy the requirements of the local population by supplying electricity, depending on the capacity adopted. The reactor can be connected to the local grid serving the requirements of local communities. During the off-peak hours of electricity generation, the surplus electricity could be utilized for charging batteries that can be used for powering vehicles used in remote and inaccessible places.

Hydrogen fuel for vehicles

In the future, the nuclear power pack could produce hydrogen in off-peak hours by using electricity, through electrolysis of water, or by using the high temperature process heat for thermochemical water cracking, depending on the economic viability and the requirements of the region.

Potable water

The waste heat from the reactor could be used for producing potable water by desalination or from brackish water or wastewater, depending on the area of deployment. Many of the places that require clean water to improve sanitation could make use of this.

Heating of condominiums

Countries with a cold climate, in addition to electricity, require heating for both residential and commercial buildings. The nuclear power packs could provide the necessary heating loads.

V–3.2.2. Features of a conceptual multipurpose nuclear power pack under study in India

The general features of the concept of a high temperature nuclear power pack are given below:

- Safety:
  - Natural circulation based passive cooling of the reactor core under normal operating conditions;
  - High heat capacity ceramic core;

  - Negative temperature coefficient of reactivity for fuel, to ensure self-stabilization and limitation of reactor power under abnormal conditions;
  - High burnup, high temperature performance capable fuel;
  - Highly negative Doppler (fuel temperature) coefficient;
  - Low core power density;
  - Burnable poison in fuel;
  - Small excess reactivity.
- Environment and sustainability:
  - Long core lifetime of ~15–20 years in operation without on-site refuelling;
  - Absence of fresh and spent fuel storages at the site.
- Proliferation resistance:
  - Absence of on-site refuelling equipment;
  - Absence of spent fuel storage at the site.
- Economics:
  - Reduced O&M personnel, due to passive features of the reactor;
  - Reduced size and weight of modular type components of the reactor, ensuring easy transport;
  - Absence of on-site refuelling requirement and fresh and spent fuel storages, easy decommissioning.

The conceptual reactor under study can be designed in the power range of 500 kW(e) to 2 MW(e) capacities, or even more, suiting the requirements of the region of deployment. Considering a nominal average per capita electricity consumption rate of 600 kW·h/a for the people of the region of deployment (this value is assumed based on the arbitrary electricity energy requirement to support the minimum daily requirements of the people in the region of interest), a single reactor of capacity 500 kW(e) to 2 MW(e) can meet the energy requirements of as many as 6600–27 000 people comfortably at a 90% capacity factor. In addition to this, if the region of deployment is islands surrounded by sea, potable water can be made from sea water using the waste nuclear energy. This conceptual reactor pack can be easily transported to the place of deployment in modular units for assembly at sites. Once fuelled, the reactor can run for 15–20 years without refuelling. This results in elimination of the necessity to store fresh and spent fuel at the reactor site. The nuclear power pack offers a variety of siting options, including populated centres as well as in remote and difficult to access areas, scattered islands, etc., and minimum reliance on local infrastructure. Developed countries with populations scattered over islands and hilly places will also find application of such nuclear power packs to meet their demands and other requirements such as heating in cold climates by utilization of the process heat from the reactor.

V–3.2.3. Economic competitiveness of the multipurpose power pack

Regions with extreme climatic conditions, which are not connected to the main electricity grid, most often suffer from shortage of electricity. Currently, they depend on hydro and diesel generator (DG) based power plants for power generation. DG sets require several thousands of litres of diesel fuel every day to meet the electricity generation demand. Remoteness, inaccessibility and difficulties in transporting diesel fuel make power generation costly. On some occasions, bad weather disturbs the supplies. Shortage of fuel leads to load shedding. In addition to this, the O&M cost of the DG sets is high. During extremely cold conditions, electricity from the hydropower plant may not be available, due to freezing of the canal water. This leads to a low utilization factor for hydropower plants in such areas. The above mentioned factors may make the competition costs high and the small nuclear power pack competitive under the targeted conditions of its application.

The nuclear power pack would use many inherent and passive safety features in its design; it is expected that it could be deployed in the vicinity of populated zones to meet all of the energy requirements of a small region. The use of high burnup fuel would result in better fuel utilization and long refuelling intervals; this would shorten the downtime owing to refuelling outages. The main coolant circulation pump would be eliminated via applying passive cooling during normal and shutdown conditions. Passive safety features are expected to reduce the number of skilled manpower required for reactor O&M. Small core sizes and small components would facilitate shop fabrication of the entire reactor, and its relatively easy transport to the site, owing to its moderate weight. The above mentioned factors are expected to reduce the specific capital costs that are otherwise high for a small reactor.

The nuclear power packs could become a cheaper energy alternative for isolated, remote and hard to access terrains where the cost of fossil fuel energy is high.

V–3.3. Economy of hydrogen distribution

Hydrogen as an energy carrier could be efficiently produced with the use of nuclear energy [V–12], either through electrolysis or by the use of high temperature process heat to drive thermochemical processes for water splitting. The produced hydrogen can either be used to produce synthetic liquid fuels, or be transported to various centres for distribution, as it could be required for direct utilization in transport applications (fuel cells).

Most published studies on hydrogen in future applications assume transport of hydrogen to the distribution centres for direct applications, as mentioned above. For such a scenario, the economy of transport of hydrogen needs to be considered, and it is one of the major parameters that will determine the extent to which hydrogen generation by nuclear reactor systems may be competitive in a certain region.

Hydrogen can be transported using several methods, either by a pipeline, or by truck, rail or ship. Transport costs vary widely, depending on the method employed. Several publications provide cost estimates of hydrogen transport by pipelines, e.g. Veziroglu and Barbir [V–13] indicate that hydrogen pipeline costs would be 50–80% higher than those of a natural gas pipeline. Kirk-Othmer [V–14] suggests that regional transport could be as much as five times more costly than that of natural gas, mainly because of the lower volumetric energy density of hydrogen. Ogden et al. [V–15] estimated the capital cost of a hydrogen pipeline at $1 million/km. In addition, Bossel et al. [II–16] mentioned that the theoretical pumping power required for moving a certain energy flow of hydrogen through a given pipeline is about 3.85 times higher than that required for natural gas. The report Survey of the Economics of Hydrogen Technologies [II–17] has examined the cost of transport of hydrogen via various means. Some of the observations are summarized in Tables V–4 and V–5.

TABLE V–4. ESTIMATED COST OF HYDROGEN TRANSPORT VIA PIPELINES [V–17]

Transmission rate (GW)	Distance (km)	Transport cost ($/GJ)
0.15	161	2.83
	805	13.84
	1609	27.23
1.5	161	0.83
	805	2.09
	1609	2.09

The data in Tables V–4 and V–5 suggest that the transport requirements would become an additional burden on hydrogen cost if the nuclear hydrogen production units are located away from the consumer points, necessitating hydrogen transport via various means to the application point. In view of this, it might be desirable to have nuclear reactors producing hydrogen near the application point. Innovative SMRs with the potential of being sited in the proximity of population centres could, therefore, become essential in future scenarios when hydrogen or its derivatives become a major energy carrier.

V–4. CONCLUSION

Future innovative SMRs have the potential of capital cost reduction for their deployment in interested countries. First of all, this is attributed to simpler design concepts incorporating passive safety design features contributing to different defence in depth levels. The expected high safety level of such innovative SMRs would facilitate their deployment near the energy consumption points, resulting in a simpler grid system with lower distribution losses, altogether enhancing the reliability and security of the supply and leading to optimal use of non-electric energy products. Such products, which may include potable water, or heat for district heating or industrial process heat applications, can be produced by innovative SMRs in a cost effective and efficient manner. Several SMRs could be constructed at the same site in clusters, using the advantages of sharing common facilities, the standardization and modular construction approach, accelerated learning, etc., which would reduce the overall cost and increase the reliability and security of the power supply compared to larger nuclear power plants.

TABLE V–5. ESTIMATED COST OF HYDROGEN TRANSPORT BY TRUCK [V–17]

Quantity transported (GJ/a)	Trip distance (km)	Transport cost ($/GJ)		
		Liquefied gas	Compressed gas	Metal hydrides
458 000–45.8 million	161	0.52–1.84	10.60	5.75
	805	2.00–3.10	41.10	21.92
	1 609	3.90–4.70	79.10–79.70	42.11

In the future, vital industrial infrastructure developments established through participation of local industries for generating and supporting innovative nuclear programmes would be essential to ensure the self-reliance and successful longevity of an energy programme in any country. Innovative SMR designs that would facilitate promotion and development of the local industrial infrastructure, mainly due to their simpler designs, could be an important factor in decision making for selection of the reactor technology in developing countries. Self-sufficiency in the infrastructure required for the nuclear technology accelerates future capacity addition through standardization and construction in series, and could lead to the competitive overall economics of innovative SMRs compared to larger nuclear power plants. Standardization could result in fast and cheap construction of high quality plants. A firm commitment to the construction of a series of innovative SMRs would potentially give local companies sufficient confidence to invest in new facilities and additional resources for enhancing production capabilities for SMR components and equipment.

Future nuclear power plant concepts, designed as compact units for the production of electricity, have the potential to meet the energy requirements of the population scattered in remote places and difficult to access areas, such as islands, mountains and deserts. Such multipurpose nuclear reactors could be easily transported to the place of deployment; they do not require on-site fuelling and refuelling and a protection zone. One of the important aspects to be considered for siting of the reactors supporting hydrogen production would be a potential for siting close to load centres. This is yet another dimension for SMRs necessitating their siting in proximity to the users.

In India, two trends of innovative SMR development are being pursued. One is related to the nearer term deployment option and builds upon the experience of the operating and planned pressurized heavy water reactors, but provides for the use of many advanced passive design features. This will be a first of a kind reactor intended specifically for technology demonstration of the use of thorium fuel and of advanced passive safety design features. Another trend, targeted for the more distant future, would incorporate innovative solutions to facilitate demonstration of the technologies for high temperature process heat applications, such as hydrogen production. This reactor would also be capable of operating as a compact power pack in remote areas.

These two future design concepts would have many advanced features, as explained in more detail above, in the areas of safety, sustainability and economics for meeting the growing energy demand, especially in developing countries.

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Annex VI

OPEN MODEL FOR THE EVALUATION OF ECONOMIC ATTRACTIVENESS OF SMALL AND MEDIUM SIZED REACTORS

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VI–1. INTRODUCTION

This annex describes the development of an open model for simulation and evaluation of the economic features of small and medium sized reactors (SMRs), being undertaken by the Politecnico di Milano in Italy. The model aims at establishing a comparative assessment of SMRs versus large reactors (LRs) as its final output. The model will allow assessment of the competitiveness of SMRs under different deployment and application conditions.

The distinctive attributes of SMRs such as replication, scalability, reversibility and standardization are briefly described below. The features of SMRs impacting the domains of generation costs (co-siting economies, learning economies, technical economies, mass production and factory fabrication economies), deployment conditions (market matching, market suitability, reduced entry barriers) and financial costs (lower financial distress, reduced risk premium) are addressed before explaining the model architecture. Other state of the art models in this regard are also discussed, along with their respective attributes. The special features of the SMR model being developed are discussed.

At the current stage of research, selected elements of the generation costs are modelled analytically. Provisions for adapting financial and external costs from other contemporary models and integrating the same into the main framework are being established.

The model has been realized as a code, and the updated version of this code is used in the case studies of SMR competitiveness in different applications, carried out within the IAEA project Common Technology and Issues for SMRs.

VI–2. ECONOMIC CHARACTERIZATION OF SMRs

Economies of scale are generally believed to drive the generation cost structure of nuclear power plants in favour of LRs. Traditional technical economic evaluations have shown that the average investment and operating costs per unit of electricity decrease with increasing plant size. However, this result cannot be directly transferred into the investment analysis of SMRs versus LRs because it relies heavily on the clause “other things being equal”. In other words, it assumes that SMRs are the same as LRs, except for size. SMRs exhibit several benefits that are uniquely available to smaller reactors and can be replicated in LRs to a limited extent. The benefits of SMRs have been reviewed by, for example, Shepherd and Hayns [VI–1], Schock et al. [VI–2] and Miller [VI–3].

Several relative features of SMRs need to be recognized and modelled to complete the relative competitiveness of SMRs versus LRs. The factors that differentiate the competitiveness of SMRs from LRs include:

- Unique factors for SMRs: These are the factors that are applicable to SMRs only, or are critically affected by differences in the design or deployment approach brought in by the SMRs.
- Common factors: These are the factors that affect SMRs and LRs in a comparable way. However, quantitative assessment of such common factors may not be straightforward.

These unique and common factors are qualitatively discussed in the following. The factors with a high priority for quantitative evaluation are presented. This list of factors is not exhaustive, and other factors may be included. Furthermore, the distinction between unique and common factors is only judgemental.

VI–2.1. Unique factors

VI–2.1.1. Investment scalability

Investments in SMRs are inherently more incremental due to smaller sizes, shorter construction times and more flexible capacity addition, when compared to LRs. In particular, the plant capacity is more readily adaptable to changing market conditions. This has far reaching implications on the generation costs, revenues and financial costs. For example, the investments in additional SMRs can be postponed (investment deferral) to the period after the planned operation date of the first SMR. The shorter construction period of an SMR would result in a higher net present value (NPV) of the investment. SMRs may have lower financial costs than a single LR of the same capacity, provided a sequenced construction of multiple SMR plants or modules is adopted. Investments in SMRs might be sequenced such that the last SMR has the same operating date as an LR of the same overall capacity, but SMRs could often offer a better match to actual demand growth. Alternatively, parallel construction of SMRs may result in an earlier operation date than for LRs (better market matching for the conditions when the demand is already in place). The first option would give a better financial performance with a smoother cash flow profile over the project lifetime. The parallel, concentrated construction of all of the modules would generate a higher overnight construction cost per kW(e) due to the loss of learning economies, and may consequently be comparable or more expensive in terms of financial expenses when compared to an LR based plant. The shorter construction time for SMRs may lead to earlier revenues for plants with such reactors. Alternatively, a staggered build of several SMRs to reach the same overall capacity may result in a longer overall project period, which will result in a lower NPV owing to positive cash flow being moved forward.

VI–2.1.2. Investment flexibility

The smaller size of SMRs translates into scalability, where the market conditions (trends of the electricity price and demand) are steady and can be relied upon for long term planning. In contrast, the smaller size of SMRs translates into adaptability, where the market conditions are highly uncertain. This is an extreme form of temporal and spatial flexibility in SMR deployment. This reversible nature of investment in SMRs becomes apparent when one focuses upon the market risks related to investments in LRs. LR investors have to cope with the swings of price and demand or localized increase (or decrease) of demand by means of long term planning, given the long lead times for LRs. As shorter term projections can be made with greater accuracy, the decision to invest may be more sound for SMRs. The economic risk of a sunk portion of the capital invested in LRs is greater because a large share of the invested capital may turn out to be idle, or consistent revenues may be foregone. SMRs allow investors to closely and quickly adapt to early signals of changing market conditions due to shorter lead times and smaller project size. The shorter lead times of SMRs allow the splitting of investments for additional units in closer proximity to the market evolution (electrical demand growth) under uncertainty. In comparison, the investment in LRs may result in an expected loss of revenues with respect to SMRs for power not taken.

In addition, temporal and spatial flexibility of SMR deployment could result in a lower cost of capital, owing to a perception of reduced risk by both the creditors and the shareholders. They could be aware that investments in SMRs are more capable of matching the new market conditions than investments in LRs, if other things are equal. Accordingly, the creditors and shareholders would demand a lower risk premium. Multiple SMRs may, therefore, have lower financial costs than LRs for a given overall capacity.

VI–2.1.3. Fitness for small electrical grids

In addition to matching economic and financial requirements, nuclear power plants need to be assessed from the point of view of power distribution and stability of the electrical grid. Some developed countries or regions, such as the western part of the European Union, are well interconnected and can support large power stations. Historically, national markets with large electrical grids have driven the development of large nuclear power reactors. Commercial reactors of 1000 MW(e) and above are quite common now. On the other hand, there are a number of countries, even in the European Union, where electrical grids are smaller and the technical infrastructure is somewhat underdeveloped. The grids of such countries are not able to accept the connection of concentrated, large power stations. The grid size, therefore, puts a limit on the application of LRs. An SMR design, tailored to this market segment, could help in meeting the rising power demands associated with economic growth and urbanization, while avoiding grid instability concerns. Moreover, SMRs might offer more flexibility in capacity addition according to the actual power offer–power demand dynamics of the electricity market (market matching).

VI–2.1.4. New design strategy and solutions

The technological choices in the design phases of a nuclear power plant project could also affect the economics of SMRs versus LRs. An integral and modular approach in the design of nuclear reactors offers a unique possibility to exploit design simplification of the plant. This could lead to a reduction of the nomenclature and number of components. As an example, integration of all of the primary components inside the reactor pressure vessel (RPV) in the International Reactor Innovative and Secure (IRIS) design developed by the international team led by Westinghouse Electric Company, United States of America (USA) helps avoid circuitous high pressure piping. A reduction in the number of safety systems/components, as well as their simplification, allows achievement of an enhanced safety level and, therefore, positively affects the economy of SMRs. Such integration also increases the compactness (power to volume ratio) of the plant, resulting in a consequent reduction of the containment volume. With a smaller footprint of the plant, further positive influences come from security considerations for a nuclear power plant. For example, a limited area of the nuclear power plant skyline reduces the probability of a terrorist air attack.

The radiation damage of the RPV of water cooled SMRs with an integral design of the primary circuit is essentially nullified by the inherent shielding provided by a thick water layer between the RPV and the core. This leads to a longer plant lifetime and the plant performance being maintained at a high level over the full lifetime of the plant. Such factors also have an impact on the levelized unit electricity cost[1] (LUEC) offered by the plant.

VI–2.1.5. Cogeneration options

In addition to electricity, SMRs may also offer non-electrical energy products. For example, part of the heat generated by a nuclear reactor can be used for district heating or seawater desalination. With respect to this, it is desirable that nuclear reactors be located close to a desalination plant or near a district heating centre. The enhanced safety level and the reduced source term of SMRs may lead to a reduction of the emergency planning zone (EPZ). Accordingly, it might be possible to locate SMRs not far from urban areas. Generically, this is not the case with LRs. The relatively small thermal power from an SMR designed for non-electrical applications may be more consistent with the thermal load or water requirements of an urban area.

VI–2.1.6. Economy of mass production

The power provided by an SMR is a fraction of the power provided by an LR. Multiple SMRs versus a smaller number of LRs would be required to achieve a given installed capacity. Therefore, bulk ordering of the process components, such as valves, pumps and tanks, would be possible for SMRs. This could allow the SMRs to achieve a mass production economy with a more standardized procurement process.

VI–2.2. Common factors

VI–2.2.1. Plant size — economy of scale

The unit size of a nuclear power plant is the first and most obvious of the common factors. Other things being equal, the economies of scale are in favour of LRs.

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[1] The LUEC is defined as the present value of the total cost of building and operating a generating plant over its economic lifetime, converted to equal annual payments, expressed as the value per unit of electricity, and levelized in constant currency units (i.e. deflated to remove the impact of inflation). It takes into account both generation costs (i.e. the production costs; see Section VI–4) and financial costs (i.e. the cost of capital; see Section VI–6).

VI–2.2.2. Modularization — economy of factory fabrication

The Generation IV International Forum (GIF), a framework for international cooperation in research and development for the next generation of nuclear energy systems, defines modularization as the process of converting the design and construction of a monolithic or a 'stuck built' plant to facilitate factory fabrication of modules for shipment and installation in the field as complete assemblies [VI–4]. It is well known that factory fabrication is cheaper than fabrication on the site. The limit is then the cost of shipping the factory built modules to a site. SMRs take a differential advantage as it is possible to have a greater percentage of factory built components, resulting in lower investment costs and, with time, better quality assurance.

VI–2.2.3. Modularity — economy of learning

The GIF also addresses modularity as an option for the construction and deployment of a larger number of standardized units [VI–4]. The modularity reduces the requirements for more expensive and time consuming on-site construction and allows a greater standardization that can be facilitated by the smaller size and lower power of SMRs. The designs of SMRs may incorporate specific technical solutions (e.g. the integral primary circuit layout, and the broader reliance on inherent and passive safety features facilitated by the size reduction) that are not applicable to current or classical LRs. Above all, SMRs rely on technical concepts that provide for design simplification and the supply of standardized components for their rapid assembly at the plant site, aiming at reduced investment and operating costs. It should be noted that, in order to reap the full benefits of the economy of learning, standardization of SMR components and replication of their manufacturing at a factory are the necessary conditions. It is known that an *N*th of a kind (NOAK) plant costs less than a first of a kind (FOAK) plant because of the lessons learned in the construction and deployment of earlier units. The learning curve generally flattens out after five to seven units. Comparing SMRs and LRs, the NOAK with associated learning economy is reached with a lower installed capacity through SMRs.

Learning would be an advantage for SMRs in the early stages of the market. The differences with LRs would eventually be equalized as the market for both groups of reactors matures. In addition to global learning (assuming that it does not matter where the units are built to reach the *N*th design), there is also additional on-site learning, obtained from the construction of successive units at the same site. This important portion of the total learning offers a higher potential advantage to SMRs, related to lower average investment costs for a given overall size of power station (which may include multiple SMRs rather than a few LRs).

However, modularity is still considered a common factor because it is also employed in recent LR designs and, therefore, has to be evaluated comparatively.

VI–2.2.4. Multiple units at a single site — learning economy and co-siting economy

SMRs allow investors to make incremental capacity additions to a power station located at the existing site. In addition to the learning economy mentioned above, this would result in an additional economy due to co-siting. The pre-project activities related to siting (e.g. acquisition of the land rights and connection to the transmission network) would be completed when construction of the second and next units starts. Therefore, certain fixed indivisible costs are saved when installing the second and subsequent units at the same site. The larger the number of SMR co-sited units, the smaller the total investment cost per unit. The other obvious advantages are related to sharing of the infrastructure and fixed costs (such as licence costs and insurances), better utilization of site resources and sharing of human resources. Moreover, multiple units on a single site ensure a higher average service factor than a single large unit for a given total generation capacity, due to lower probability of simultaneous failure of all of the modules. Finally, the higher number of units allows a smart refuelling outage scheduling, permitting lower replacement power during the planned outages. Of course, more SMRs need to be deployed for the same amount of power attained with LRs. SMRs and LRs have similar co-siting considerations, and several multiunit sites with thousands of installed MW(e) do exist. Therefore, while, in principle, this factor favours SMRs, a case by case comparative evaluation needs to be carried out.

The factors summarized in Table VI–1 need to be taken into account when comparing SMRs and LRs.

VI–2.2.5. Front end investment — reduced entry barrier

Specific characteristics of SMRs such as smaller size, simpler design, increased modularization, higher degree of factory fabrication and serial fabrication of the components may lead to a shorter construction time. In fact, the currently projected schedules for advanced SMRs are 3 years for FOAK plants. The construction period might then be reduced to as low as 2 years for NOAK plants. The low upfront investment cost may be the critical factor for a small utility or a country with limited financial resources. Therefore, for a given size, multiple SMRs may attract a larger number of investors than a single LR of the same capacity. The lower front end investment for each module, together with a staggered construction option, produces a lower average capital employed. Table VI–1 synthesizes the distribution of the mentioned benefits and disadvantages across the various factors.

TABLE VI–1. NUCLEAR POWER PLANT FEATURES AND THEIR IMPACTS — EXPECTED POSITIVE (+) AND NEGATIVE (−) CONTRIBUTIONS TO SMR ECONOMICS

Nuclear power plant feature	Generation costs	Financial costs	Meeting diverse market demands
SMR unique factors			
Scalability		Investment deferral (+); More smooth cash flow profile (+)	Demand matching (+)
Investment flexibility		Reduced risk premium (+)	Risk matching (+)
Compatibility with small electrical grids			Suitability for many markets (+)
New design strategy and solutions	Technical progress economy (+)	Reduced risk premium (+)	
Cogeneration options			Suitability for many markets (+)
Mass production	Mass production economy (+)		
Factors common to SMRs and LRs			
Size	Economy of scale (−)		
Modularization	Economy of factory fabrication (+)		
Modularity	Learning economy (+)		
Multiple units at a single site	Co-siting economy (+); Learning economy (+)	Reduced risk premium (+)	
Front end investment		Reduced risk premium (+); Lower average capital employed (+)	Reduced entry barrier (+)

Note: LR: large reactor; SMR: small and medium sized reactor.

The degree to which the unique features of SMRs are able to outweigh the reduction of average generation costs associated with LRs and owing to the economy of scale is dependent on the market and application conditions. A parametric model could be helpful, allowing the user to analyse the sensitivity of SMR economics relative to LRs.

VI–3. DESCRIPTION OF THE MODEL FRAMEWORK

VI–3.1. General description

The model performs economic and financial calculations of an investment in nuclear power plants in the small to medium size range versus those in a large power range. The simulation of an investment is performed for a given total power generation capacity, which could then be represented either by multiple SMRs or by a single LR. A methodology to evaluate the relative economic and financial advantages/disadvantages offered by the two different plant configurations and technologies is adopted. The investment model operates with the main parameters used in economic and financial analysis (such as revenues, operating and capital costs and financing costs), and relies on a cash flow analysis over the plant lifetime. The output of the investment model is a set of indices measuring financial performance of an investment from the investor's point of view. The model deals with both the profitability for a private investor and the economic soundness for a public stakeholder, and is aimed at supporting decision making regarding the selection of a particular nuclear technology. For the financial model, profitability of an investment rather than its social value is assumed to be of prime importance to both the public and public investors. Considering that the investment profitability approximates its social value, if the wholesale electricity market is competitive, and that energy and environmental regulations induce the investors to take into account the external costs (e.g. via carbon taxes for CO_2 emissions), such an assumption is acceptable. Detailed discussion of this assumption is beyond the scope of the study performed.

The investment model performs a sensitivity analysis to assess the impact of the key variable parameters on the output indices. Considering multiple SMRs on the same plant site, a range of scenarios from staggered deployment of the SMRs to a parallel and concentrated construction of all of the SMRs is considered.

The output of the investment model is an input for a multiattribute evaluation model, where the economic/financial performance is merged with the external, not always unambiguously quantifiable, costs or just benefits of the SMRs. The product is a synthetic assessment of the relative competitiveness of the SMRs for specified conditions of their deployment and application, versus a larger reactor option.

As each scenario is country dependent, the objective is to evaluate the profitability of an SMR technology under given conditions. The model does not attempt to demonstrate that SMRs are always more competitive than nuclear power plants with LRs. Rather, the model is developed to show that under certain circumstances, SMRs may represent the optimal solution for the production of electricity and, possibly, of other products.

Several factors are obviously country specific; they include labour costs, raw material (commodity) costs, the cost and availability of capital, and characteristics of the electricity grid (such as load capacity and interconnections). Therefore, some investment solutions could be rated optimal within a certain scenario and in a certain country, but re-evaluation would be required for a different scenario in a different country.

The general model for evaluation of the investment attractiveness is framed into a cluster of several submodels. Figure VI–1 shows the overall structure of the model.

The submodels that are adopted and linked to the main model include the:

(1) Generation cost model;
(2) Revenue model;
(3) Financial model;
(4) External factors model;
(5) Project attractiveness.

Among the literature in the public domain, a notable recent effort in the development of an economic model is by the Economic Modelling Working Group (EMWG) of the GIF [VI–4], devoted to next generation reactors but validated on the Generation III and III+ nuclear reactors. The strategy [VI–5, VI–6] is similar to the model being proposed in its generation cost part. While the EMWG model is a plant based model, models taking into account other elements of a nuclear energy system exist, such as the DANESS code [VI–7 to VI–9], which are capable of treating multiple plants and fuel cycle facilities in regional and global scenarios of deployment.

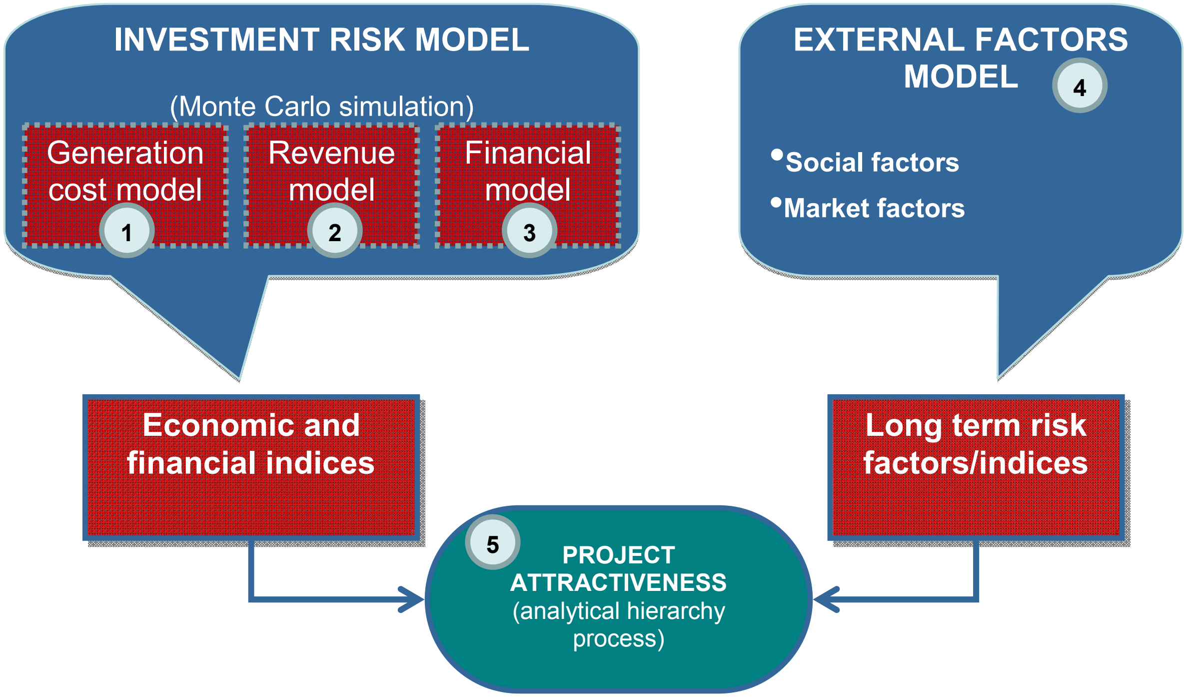

FIG. VI–1. Framework of a general model for the evaluation of investment project attractiveness.

The ultimate objective of the current study is to propose a plant based, country independent model for comparative assessment of investment attractiveness of nuclear power projects. Therefore, all models available in the open literature, including those developed by the IAEA, will be considered and taken into account, as appropriate.

VI–3.2. Existing models

The model being developed is a contribution to the rising global effort on modelling of nuclear power deployment. There is a revamped interest in this subject in view of the worldwide nuclear renaissance, with plans for consolidating the nuclear power programmes of many developed and developing countries. Comparative economic analysis is and will be the core element of such modelling.

Several codes have been developed to deal with dynamic nuclear energy system strategies at regional or multiregional level. All of the following models are based on mass flow analysis:

- COSI (Atomic Energy Commission, France);
- DANESS (Argonne National Laboratory, USA);
- DESAE (UNK Group, Russian Federation);
- ORION (Nexia, United Kingdom);
- OSIRIS (NNC, United Kingdom);
- PROGNOSIS (Kurchatov Institute and Rosatom, Russia);
- SuperStar (TEPCO, Japan);
- VISTA (IAEA).

These models consider different types of reactor; some of them are linked to exogenous detailed reactor physics codes. COSI, DANESS, DESAE, ORION, OSIRIS and PROGNOSIS calculate the LUEC. DANESS also involves a cash flow analysis. Table VI–2 summarizes the main features of these codes.

In particular, the COSI code can take into account investments, operating and decommissioning costs for reactors, costs of fuel cycle facilities and the actualization rate. It calculates levelized generation costs per kW·h.

TABLE VI–2. FEATURES OF THE CODES CURRENTLY AVAILABLE FOR ANALYSIS OF NUCLEAR DEPLOYMENT SCENARIOS

Code/scope	COSI	DANESS	DESAE	DYMOND	NFCSim	ORION	OSIRIS	PROGNOSIS	SuperStar	VISTA
Equilibrium analysis										
Single reactor	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Reactor park	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Dynamic analysis										
Regional reactor park	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Multiregional reactor park	✓	✓	✓		✓	✓	✓			✓
Mass flow analysis										
Natural U–Th use	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Front end capacity requirements and use	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Reactor core loading	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Back end capacity requirements and use	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Separated material inventories	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Disposal requirements	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Related functionalities										
Isotopic composition	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Decay heat	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Reactor core management	✓	✓	✓	✓	✓	✓	✓	✓		
Economic analysis										
Levelized generation cost	✓	✓	✓			✓	✓	✓		
Investment requirements		✓	✓			✓		✓		
Cash flow analysis		✓								
Environmental analysis										
Life cycle inventory										
Life cycle analysis										

TABLE VI–2. FEATURES OF THE CODES CURRENTLY AVAILABLE FOR ANALYSIS OF NUCLEAR DEPLOYMENT SCENARIOS (cont.)

Code/scope	COSI	DANESS	DESAE	DYMOND	NFCSim	ORION	OSIRIS	PROGNOSIS	SuperStar	VISTA
Waste management analysis										
Repository impact	✓	✓		✓					✓	
Sociopolitical factors										
Proliferation risk				✓						
Availability of the code										
Free			✓							✓
Licence agreement	✓	✓		✓	✓			✓	✓	
Commercial						✓	✓			

Note: The ✓ symbol indicates that the functionality or capability is available in the code.

OSIRIS is an investment appraisal model that calculates unit electricity generating cost; it discounts the FOAK costs, capital costs, fuel cycle front and back end costs, decommissioning costs, reactor operation and maintenance (O&M) costs, and raw material costs, all of which are specified as costs over the lifetime of a reactor in the code's input.

Among the recent efforts on economic modelling, the Generation IV spreadsheet calculation of nuclear systems (G4-ECONS) model of the EMWG of the GIF [VI–5] should be mentioned. It is an Excel sheet code to calculate generation costs specifically for next generation reactors. This model includes a highly detailed fuel cost module and is validated on Generation III and Generation III+ reactor systems. LUEC is the main output of this model. The EMWG also provides detailed cost estimation guidelines in an attempt to set up uniform accounting standards.

The French SEMER code [VI–10] is a simplified code for economic evaluation of nuclear based energy production systems. Fossil fuel based systems are also included to provide a basis for the comparison of costs. SEMER includes three types of model libraries: a global model, for a rapid estimation; detailed models, for a finer cost evaluation of individual components and circuits in a pressurized water reactor (PWR); and fuel cycle models, for PWRs, high temperature reactors and fast breeder reactors. The model allows cost evaluations related to all steps in the nuclear fuel cycle, including fuel reprocessing and final disposal, to be performed.

Finally, the IAEA develops and offers a set of comprehensive economic models. The available codes from the IAEA are:

- — MAED (model for analysis of energy demand) evaluates future energy demands based on medium to long term scenarios of socioeconomic, technological and demographic development.
- — WASP (Wien automatic system planning package) is used in developing countries for power system planning. It determines the optimal long term expansion plan for a power generating system. Constraints may include limited fuel availability, emission restrictions, system reliability requirements and other factors. Optimal expansion is determined by minimizing discounted total costs.

- ENPEP (energy and power evaluation program) is a program for evaluation of energy system development strategies. It is linked to the MAED and Wien models, computes market prices and energy demand/supply balances under certain market conditions, and also estimates environmental burdens from the energy system.
- MESSAGE (model for energy supply systems and their general environmental impacts). The code is able to formulate and evaluate alternative energy supply strategies for user defined constraints, for example, new investment limits, market penetration rates for new technologies, fuel availability and trade, environmental emissions, as well as being able to analyse energy/electricity markets and climate change issues.
- SIMPACTS (simplified approach for estimating impacts of electricity generation). The code estimates the environmental impacts and external costs of different electricity generation chains, covering health, agricultural, forest and materials damage, airborne and water pollution, as well as solid waste.
- GTMax (generation and transmission maximization) model. This code is based on a mixed integer linear programming approach. It maximizes the net revenues of power systems by finding a solution that increases the income while keeping expenses at a minimum. The model computes and tracks hourly energy transactions, market prices and production costs.
- FINPLAN (financial analysis of electric sector expansion plans). The code is a tool for assessment of the financial viability at a plant level or a system level. FINPLAN is used for comparative assessment of energy sector investment options (different energy sources) in competitive capital and electricity markets, based on financial performance ratios. In addition, FINPLAN helps to identify the selling price of electricity that would permit payback on investments. It was completed in 2001 and has been mainly employed in country scenario assessments. It was released on a pilot basis for the project on comparative studies of energy supply options in Poland for 1997–2020 using the results obtained by GTMax as inputs. It should be mentioned that, out of the IAEA models, it is the architecture of the FINPLAN code that shows a similarity to some of the features of the SMR 'open' model. Both base their analysis on projected cash flows and produce key financial ratios and other financial indicators as outputs. Both prescribe a sensitivity analysis of the output values. The forecasts developed with the FINPLAN model take into account price sensitivity to exchange rates, fluctuations in demand and foreseeable inflation rates for both domestic and foreign currencies. FINPLAN has been revised with input from commercial bankers and other experts to permit assessment of energy sector investment options in competitive capital and electricity markets.

The IAEA offers the Desalination Economic Evaluation Program (DEEP) model. This is an Excel based simplified model that addresses the cogeneration of desalinated water and electricity. It enables a side by side comparison of different design alternatives to identify the lowest cost cogeneration technology.

The purposes and features of the SMR 'open' model under development line up with the FINPLAN model and, in this respect, the new model can be considered as a complement of FINPLAN. However, the new model is being developed specifically to take into account, in detail, all factors important for a comparative economic assessment of SMRs versus larger reactors. In addition, the new model is able to take into account the so-called additional, non-quantifiable factors affecting the investment attractiveness, through a multiattribute evaluation model. The SMR 'open' model, thus, offers a comprehensive project evaluation that encompasses many factors, with financial profitability being only one of them.

The SMR 'open' model is being developed as a strategic decision making support tool for both institutional and private investors. This model is being configured as an open model with respect to existing economic codes, to the extent that it has to be adaptable to be linked to some of them, to create a more comprehensive and flexible architecture and, in this way, to act as an exhaustive, detailed and customizable analysis tool.

On the basis of the available information, Table VI–3 indicates the links between the SMR 'open' model and some of the codes presented here. The evaluation capabilities of some modules of the SMR model could be strengthened if such links were established. The 'open' model strategy also allows co-development of the models included in the overall structure.

TABLE VI–3. MODULES OF THE SMR ‘OPEN’ MODEL AND POSSIBLE LINKS TO OTHER CODES

Codes	Modules of the SMR ‘open’ model				
	Generation cost model	Revenue model	Financial cost model	Investment model	Other factors
COSI	✓				
DANESS	✓				
DESAE	✓				
DYMOND					
NFCSim					
ORION	✓				
OSIRIS	✓				
PROGNOSIS	✓				
SuperStar	✓				
VISTA					
SEMER	✓				
MAED		✓			
WASP					
ENPEP		✓			✓
MESSAGE					✓
SIMPACTS					✓
GTMax	✓	✓			
DEEP					
FINPLAN			✓	✓	

Note: The ✓ symbol indicates that the functionality or capability is available in the code; SMR: small and medium sized reactor.

VI–4. THE GENERATION COST MODEL

Output: total generation costs over the economic lifetime of the plant (input to the investment module) and front end investment (input to the revenue module).

Inputs: reactor technology (LRs versus SMRs), plant size, economic plant lifetime, construction time, standardization, thermal efficiency, number of serial and on-site units, and supplied quantities (output of the revenue module).

Parameters/forecasts: wages, retail price index, fuel price.

Note: The parameters (and forecasts over the economic lifetime of the plant) should be derived from the existing ancillary models and outlooks. These are country specific and common to LRs and SMRs.

The generation cost model is a starting and basic model of the complete set of models. Its main objective is to evaluate a series of generation costs of electricity corresponding to the plant deployment scenario, given cash flow expenditure over the whole plant lifetime. The module has to be flexible and sufficiently open to be able to accommodate the data for new reactor technology solutions (Generation IV, International Project on Innovative Nuclear Reactors and Fuel Cycles, Global Nuclear Energy Partnership). Moreover, the module should be able to consider closed, partially open or open fuel cycles.

The module has to be applicable in an international scenario. The insurance, tax and account management rules should be customizable to the country.

The generation costs can be grouped into four main items:

(a) Capital (construction plus interest) costs;
(b) O&M costs;
(c) Fuel and fuel cycle costs;
(d) Decontamination and decommissioning (D&D) costs.

The module should also take into account different possible SMR plant configurations and deployment strategies (size of the plant, multiple modules on the same site, centralized versus distributed deployment strategies, staggered construction strategies).

The general features of the module match those identified by the EMWG GIF [VI–5]:

- Simplicity: Some SMRs are still in the design and development phase. The availability and quality of the information on costs could still be limited and preliminary. This fact implies that complex economic models, such as the US Council for Energy Awareness (USCEA) model, or some models used by merchant banks or non-governmental organizations to evaluate competitiveness of nuclear technology versus other energy sources, are not suitable for the objective. The module has to be able to evaluate the cost of the MW·h produced using different nuclear power plant solutions. This module is to be integrated with the other modules for a global investment evaluation.
- Universality: SMRs, as well as some new generation reactors in general, are designed to be built and operated in many countries, including developing countries [VI–11]. The module has to be customizable in a simple way to the country specific situation in terms of taxes, discount rates, labour costs, regulatory rules, etc. For example, the G4-ECONS model handles this via a discount rate selection option.
- Transparency: Algorithms should be clearly identifiable and visible in such a way that the user can comprehend how a certain value is calculated and that the rule can be easily modified according to the country specific requirements. A spreadsheet appears to be the most viable approach.

- Adaptability: It has to be allowable to link different parts of the model to other algorithms, models or specific data. As an example, for a specific nuclear power plant solution, some indirect cost values could be substituted by a link to an external model that would evaluate these costs as a function of the reactor power (scale economy model) or other design variables.

Adaptability is of paramount importance, as SMRs are still in the design phase, and the detailed bottom-up costs may not yet be available. These are, however, expected to become available as the development of the SMR model progresses. Therefore, a simplified top-down estimation of direct costs is required. Among the available techniques for a simple evaluation of the costs in the nuclear sector, those included in the French SEMER code seem to be compliant with this objective.

The model has been developed to evaluate the economic characteristics of different innovative reactors and calculates the generation costs in cases when the detailed information is not yet available, using equations with the following input dataset:

- Reactor power;
- Number of units on the site;
- Number of units to be built in series;
- Construction time;
- Plant lifetime;
- Thermal cycle efficiency;
- Labour cost;
- Load factor;
- Service factor.

Another study [VI–12] evaluates, in a parametric way, the generation costs as a sum of two components: the first item is a function of the installed electric power (main nuclear steam supply system and balance of plant components); and the second item is independent of the size (e.g. service buildings, auxiliary systems and laboratories).

To begin the development of a generation cost module, it seems reasonable to use simplification features similar to those adopted by the EMWG. These are:

- The costs over the plant life cycle can be broken down into two basic phases of the plant lifetime — the construction phase and the operational phase. Since detailed costs are usually not available, a given expenditure or cash flow profile (e.g. the cumulative expenditure S-curve) during the design/construction/startup/financing period is assumed, leading to a total capitalized cost. The annual, levelized cost for a multi-year operational period over the economic lifetime is obtained, taking into account the capitalized cost amortization, the D&D fund growth, and all operational costs and expenditures.
- Escalation cost factors or tables can be avoided at a preliminary stage.
- Open fuel cycles and cycles with limited or full recycle can be modelled, but only two types of fuel cost, namely the initial core cost and the reload fuel cost, are adopted. The unit costs of fuel cycle services and materials are in constant currency for the lifetime of the plant.

As the fuel and fuel cycle cost modelling can be executed in a complex and detailed manner (as in the Organisation for Economic Co-operation and Development (OECD) Nuclear Energy Agency or the USCEA/Nuclear Energy Institute model), which could result in an extra burden when compared to the other models, an equilibrium strategy followed in the EMWG and DANESS codes could be adopted.

Then, the main macro-items for the cost break-down are [VI–6, VI–13]:

- Research, development and design;
- Licences and permits;
- Construction;
- Interests;

- O&M;
- Fuel;
- D&D.

The generation cost model will provide an evaluation of the LUEC (currency unit/MW·h), corresponding to the total cost of construction and operation of a nuclear power plant over its lifetime and expressed as a constant over time value.

In general, the cost generation model is a total cost function defined at a plant level. In the short run, the total cost TC (€) is a function of the supplied quantity q (MW·h), the unit size S (MW(e)), the specific reactor technology T (e.g. whether this is an LR or an SMR) and a set $\mathbf{X}$ of other technical and financial factors:

$$\mathrm{TC} = \mathrm{TC}(q;S,T,\mathbf{X}) \tag{VI–1}$$

Economies of scale, mass production, factory fabrication, learning factors, co-siting and innovation by design can be taken into account through variables $\mathbf{X}$ in Eq. (VI–1). The cost function is assumed to be separable into the following four components:

- Total capital cost function;
- Total operating cost function;
- Fuel cost function;
- Decommissioning cost function.

Once the analytical properties of the cost functions are identified, different functional forms can be specified, and their parameters can be estimated through statistical techniques or calibrated through numerical simulations. The model can then be validated against costs realized in existing nuclear power plants.

VI–4.1. Capital cost model

Nuclear power plants are known to be capital intensive, with long construction times and high interest during construction costs. In order to present a parametric and relative (to other nuclear power plants) analysis of SMRs, a detailed evaluation is, therefore, required. The important key factors in such an evaluation are discussed in the following.

VI–4.1.1. Economies of scale

The decrease in the average costs over a number of SMRs is, inter alia, due to the costs incurred in the pre-project activities such as siting and licensing. These are incurred for the first reactor, and will be reduced for subsequent reactors at the same site. The economies of scale may also be affected negatively by the lower operating efficiencies of smaller plants (e.g. lower thermal efficiencies) or by personnel specializations (when such specializations are required by the SMR design).

The economies of scale with respect to capital costs (costs incurred for the initial construction)[2], are defined as follows. Given the total capital costs TC^{I} (€) as a function of, among other factors, the unit size S (MW(e)), the capital cost elasticity to the size of generating units is:

$$n^{\mathrm{C}} = \frac{\partial \mathrm{TC}^{\mathrm{I}}/\mathrm{TC}^{\mathrm{I}}}{\partial S/S} \tag{VI–2}$$

If the n parameter is smaller than one, the economy of scale exists in investment or in O&M. The closer the n value is to zero, the larger the economy of scale.

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[2] See Table VI–5 for cost items that are included in the investment cost.

Costs incurred after the initial construction include fuel and O&M expenses. Capital expenditures related to the facility additions/modifications [VI–14] are investment costs in nature, and should be included as construction costs.

Bowers et al. [VI–15] reviewed the previous technical economic estimates of nuclear investment costs at a plant level. The results appear to be quite scattered due to methodological and sample differences. However, the published data converge when it comes to the evaluation of the n^{I} parameters, which is consistent with the hypothesis of economies of scale (see Table VI–4).

TABLE VI–4. ECONOMIES OF SCALE IN THE INVESTMENT COSTS [VI–15]

Reference[a]		*n* parameter	Notes
[—]	1968	0.75	LWR total cost
[—]	1968	0.51	Total cost
McNelly and Koke	1969	0.64	Total cost
Bennett and Bowers	1971	0.68	Total cost
Leedy and Scott	1973	0.40	LWR direct cost
Davis	1975	0.47	BWR total cost
Mandel	1976	0.46	LWR total cost
Woite	1976	0.71	Direct and indirect costs
Comtois	1977	0.86	LWR total costs
	1977	0.76	LWR total costs
Mooz and Rand	1978	0.8/0.5/0.7	LWR regression analysis of historical data; marginal statistical significance Different assumptions
Mooz and Rand	1979	1	LWR regression analysis of historical nuclear plants; no statistically significant economy of scale was found
Crowley	1978	0.45	Direct and indirect costs
Woite	1979	0.40	PWR direct and indirect costs
Gehring	1979	0.24	LWR direct and indirect costs
	1979	0.49	Total costs; used in CONCEPT CODE 5
Fjeldsted	1980	0.59	Total costs; source: F.S. Aschen, Planning Fundamentals of Thermal Power Plants, John Wiley and Sons, New York (1978) Includes allowance for the escalation and interest during construction
McMahon	1980	0.43	Direct and indirect costs
Nieves et al., Battelle	1980	0.25	Regression analysis of historical data; direct and indirect costs and constant dollar interest during construction For nuclear units, Komanoff found a 13% cost reduction in $/kW(e) for doubled size
Komanoff	1981	0.80	Regression analysis of historical data; direct and indirect costs

TABLE VI–4. ECONOMIES OF SCALE IN THE INVESTMENT COSTS [VI–15] (cont.)

Reference[a]		*n* parameter	Notes
McMahon	1981	0.43	Total costs; 0.92 for 100–600 MW(e) oil fired units
Crowley	1981	0.40	Direct costs
Nobile and Kettler	1982	0.63	Regression analysis of historical data; direct and indirect costs and constant dollar interest during construction
	1982	0.53	LWR direct and indirect costs
	1982	0.63	LWR engineering cost estimates
Perl	1982	0.49	Regression analysis of historical data

[a] Full bibliographical details of the references can be found in Ref. [VI–15].

Note: BWR: boiling water reactor; LWR: light water reactor; PWR: pressurized water reactor.

Economies of scale in the investment activities are found to be at a more disaggregated level, as shown by the United States Department of Energy [VI–16] (see Table VI–5). The average investment costs for individual items, on average, decreases with plant size. Some set-up activities and indivisible resources, such as land rights, structures or electrical systems play a major role.

The notion of strong economies of scale at plant level in nuclear generation is also, to some extent, challenged by more recent economic studies.

In their study of economies of scale at plant level, Marshall and Navarro [VI–17] revised the widespread concept of overnight costs[3]. Under a definition of capital costs for investment more related to economic theory, a set of Japanese nuclear plants cease to show increasing returns to plant size for investment activities. Rungsuriyawiboon [VI–18] uses advanced estimation techniques to sum up investment, fuel and operating costs for a sample that is more up to date than those used in previous studies (i.e. the US nuclear plants that were observed over the period 1986–1998). Most nuclear utilities are shown to have been overinvested over time. While the short run economies of scale are very strong, the long term economies of scale, which are economies of scale net of the effects owing to capacity saturation, are present, but are by far weaker (similar to the findings of Rhine [VI–19] for a set of US electrical utilities, at company level)[4].

In conclusion, a large number of traditional technical economic studies provide evidence of strong economies of scale, in both investment and operation. However, recently performed economic research indicates that this may be related to biased measures of the investment costs or to the overinvestments that frequently result in excess capacity.

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[3] Overnight cost usually refers to the hypothetical, estimated capital (construction) cost of a facility, either a power plant or a transmission line, in current year currency (e.g. euros, 2007), assuming that the facility could be built overnight. This is usually the starting point for developing a facility cost estimate because the engineer estimates how much material and how many person-hours would be required to fabricate and build the facility, all in current year currency. In the nuclear sector, the (total) overnight cost is the base construction cost plus the applicable owner's cost, contingency and first core costs. As it may take several years to obtain permits and other required approvals for power plants, and it may take years to construct, the escalation/inflation, interest on borrowed funds and other factors working on the overnight cost cause the final capital cost of the plant to actually be higher than the overnight cost.

[4] Since the pioneering econometric study by Christensen and Green [VI–20], a parallel line of research empirically explores costs at an electrical utility rather than at plant level. For many utilities that operate multiple reactor units, cost savings other than from economies of scale may result from reliance on corporate resources. Kamerschen and Thompson [VI–21] estimate that the nuclear generation costs, net of the so-called politically determined costs (e.g. licensing delays), may outperform fossil fuel generation costs. Thompson and Wolf [VI–22] confirm that differences exist and enlighten the role played by the region of plant location. Rhine [VI–19] finds that economies of scale at a utility level are overestimated in previous works; with both nuclear and fossil fuel technologies, electrical utilities tend to overinvest.

TABLE VI–5. ECONOMIES OF SCALE IN INDIVIDUAL INVESTMENT ITEMS [VI–16]

Cost items	*n* parameter
Direct costs	
Land and land rights	0.00
Structures and improvements	0.59
Reactor/boiler plant equipment	0.53
Turbine plant equipment	0.83
Electrical plant equipment	0.49
Miscellaneous plant equipment	0.59
Main condenser heat rejection system	1.06
Indirect costs	
Construction services	0.69
Home office engineering and services	0.60
Field office engineering and services	0.69
Owner’s costs	0.64
Cost weighted average	0.64

VI–4.1.2. Learning economies and co-siting economies

Learning economies result from the replicated supply of SMR components and from the replicated construction and operation of SMRs. In other words, the replication and related learning economies are the joint effect of small size and standardization, as discussed and modelled by Lester and McCabe [VI–23], David and Rothwell [VI–24, VI–25], and Carayannis [VI–26]. This allows investors who adopt SMRs to experience lower average investment costs and average operating costs compared to investors who adopt LRs.

Let N^S, N^U and N^W be, respectively: the number of SMR units already installed and operated by the utility and its contractors on the site; the number of other units of the same SMR concept installed and operated by the utility and its contractors within the plants run by the same utility in previous years; and the number of units of the same SMR concept produced by the supplier in previous years and offered to other utilities throughout the world. The sum is equal to the total number of units of the same SMR concept already supplied and constructed, N. The total capital costs TC^I (€) are a function of, among other things, the plant size S (MW(e)) and the cumulative number of world, utility and site units N^W, N^U and N^S. The total investment cost elasticity to N^i, $i = \{W, U, S\}$, is:

$$l^i = \frac{\partial \mathrm{TC}^\mathrm{I}/\mathrm{TC}^\mathrm{I}}{\partial N^i/N^i} \text{ for } N^i > 1 \tag{VI–3}$$

If the l^i parameter is below zero, given the plant size, economies of learning are said to exist in investment costs. However, the learning effects are stronger for early units and become diminished for the following (and cumulative) units. Accordingly:

$$l^i \leq 0 \text{ and } \frac{\partial^2(\mathrm{TC^C/TC^C})}{(\partial N^i/N^i)^2} \geq 0 \quad \text{(VI–4)}$$

Two arguments are worth consideration regarding the role played by the accumulated number of SMRs in driving down the investment costs.

First, the co-siting economies, consisting of the fixed and semi-fixed costs shared by a number of SMRs. For SMRs, these costs will be lower than for LRs of the same overall capacity.

Second, the SMRs installed at a certain site allow a benefit resulting from the three level learning economies, that is, from cost reduction effects related to the accumulated experience of the supplier, the utility and the plant operator, to be obtained. The SMRs at other sites of the same utility bring in learning economies owing to the accumulated experience of both the supplier and the utility. It is preliminarily accepted that the learning path is pursued at a faster rate when an additional unit is installed on the same site, rather than at other sites, operated by the same utility or by other utilities, due to extra learning effects that are related to the experience of the site personnel and to the local network of contractors [VI–26, VI–27]:

$$l^S \leq l^U \leq l^W \leq 0 \quad \text{(VI–5)}$$

where

l^S is the site learning economy;
l^U is the utility learning economy;

and l^W is the world learning economy.

VI–4.1.3. Design strategies and innovative solutions

Shepherd and Hayns [VI–1], Schock et al. [VI–2] and Miller [VI–3] illustrated that certain technical solutions embodied in SMR design are able to reduce the investment and operating costs, for a given plant size. The most relevant elements of the SMRs are standardization of components and a broader safety by design approach. Standardization is at the origin of more efficient supply, construction and operation (see Ref. [VI–28] for a general discussion of the effects of standardization achieved through design modularity). In addition, standardization enables the suppliers and the utilities to reap more rapidly the learning economies [VI–24 to VI–26]. At this stage of the research, the nature and role of standardization still needs to be analysed and modelled.

The safety by design approach leads to elimination or a substantial reduction of both active and passive safety systems, compared to the reference plant. Such reduction and simplification of the components allows reduction of the overnight costs due to both reduced labour and cheaper equipment items.

VI–4.2. O&M cost model

O&M costs are the expenditures, fixed or variable, related to the decisions and actions regarding the control and upkeep of property and equipment of a nuclear power plant. These are inclusive, but not limited to, the following [VI–29]:

- Actions focused on scheduling procedures, and work/systems control and optimization;
- Performance of routine, preventive, predictive, scheduled and unscheduled actions aimed at preventing equipment failure or decline with the goal of increasing efficiency, reliability and safety.

The O&M costs are all costs related to O&M of the plant to keep it in line with best practices, excluding the fuel costs, which are considered separately. Expenses for O&M start with commercial operation and continue through the operating life of the plant. More than 70% of O&M costs are labour related costs [VI–30]. The GIF provides an annualized O&M code of account (COA) description [VI–4], as shown in Table VI–6.

TABLE VI–6. COA DESCRIPTION FOR THE O&M COSTS

COA	Description
O&M staff	Includes all O&M personnel assigned to the plant site
Management staff	Includes all management personnel assigned to the plant site
Salary related costs	Cost of pensions and benefits, including workers' compensation insurance, provided for on-site and off-site staff. The method of calculation will vary by nation. In some countries, these are so-called social costs
Operations, chemicals and lubricants	Can consist of a mix of variable and fixed costs; includes non-fuel items such as resins, chemicals, make-up fluids; includes costs of management and disposal of operational radioactive waste
Spare parts	Purchased spare parts for operations of the plant
Utilities, supplies and purchased services	Consumables, operating materials and equipment, radiation protective worker clothing, office supplies; can consist of variable and fixed costs; consists of materials and other unrecoverable items, such as small equipment and tools required for maintenance. In the USA, these accounts include Nuclear Regulatory Commission annual fees and review costs, as well as other routine safety, environmental and health physics inspections. Other nations' annual costs for this category will depend on their regulatory environment. It also includes purchased activities by personnel not assigned full time to the plant site, e.g. safety reviews, off-site training, environmental monitoring, meteorological surveys, power planning, fuel studies and other owner home office activities directly supporting the plant. Some plants now use off-site crews for contract refuelling
Capital plant upgrades	Total cost of large capital items that must be purchased after commercial operation starts (e.g. steam generator replacements), averaged per year over the economic lifetime of the system; can be estimated as a percentage of the base cost per year
Taxes and insurance	Costs for commercial and government liability insurance, property damage insurance and replacement power insurance; includes property taxes, sales taxes and any other taxes that can vary by country
Contingency annualized O&M costs	Allowances for contingency costs for the desired confidence level of O&M costs

Note: COA: code of account; O&M: operation and maintenance.

A detailed account description could be particularly useful in a bottom-up approach. This is not necessarily the case for all SMRs, as many are currently in the early stages of development. For such cases, it is more appropriate to focus on some cost drivers that lead O&M costs. One is the economy of scale and technical saving, which has already been described in Section VI–4.1. According to common knowledge of power plants [VI–31 to VI–33], economy of scale is also the almost unique driver for O&M costs and, therefore, the methodology used for capital costs can also be applied to O&M costs.

Further drivers specific to O&M costs are given below.

VI–4.2.1. Multiple units on a single site

The presence of one or more additional units is a lever for the O&M cost competitiveness of SMRs. In fact, some advantages can be obtained from:

(a) Sharing of the non-power structures and related staffing, and administrative and general expenses, which are not directly related to the number of units in the power station;

(b) Reduction of costs of the licences, taxes and insurance; some are una tantum (‘non-recurring allowance’) expenses not depending on the presence of one or more units on the site.

On the other hand, it should be taken into account that O&M costs depend on compliance with the staffing requirements and safety standards set by the regulatory body. Here, the commissioning and O&M cost savings for SMRs could be offset to some extent.

Summarizing, it seems reasonable to assume that the cost reduction decreases with the number of units on the site. A power function, as proposed by Bowers et al. [VI–31], can be applied:

$$\text{O\&M} = f(\text{size}) \times (\#\text{units})^{n} \quad \text{(VI–6)}$$

VI–4.2.2. Reactor technology concept

The historical O&M cost performance of nuclear power plants could be partly explained by technological differences of the plants. In fact, different designs have different safety requirements and related costs. Some studies found a statistical relevance of the plant technology, specifically in the comparison of PWRs and boiling water reactors. When appropriate, this factor should also be taken into account.

VI–4.2.3. Plant outages

Nuclear power plants could be shut down either for planned outages (fuel reloading) or for forced outages. The effect of power plant outages is twofold, bringing in an additional cost and also a time extension. In fact, each stop of operation requires on-site and off-site staffing to perform maintenance operations and reduces the capacity factor (CF) with an associated opportunity cost (loss of power generation). The CF is defined as:

$$\text{CF} = \text{availability} \times \text{average power level} \quad \text{(VI–7)}$$

$$\text{availability} = \frac{8766 - \text{POH} - \text{FOH}}{8766} \quad \text{(VI–8)}$$

where

POH is the planned outage hours per year for fuel substitution;
FOH is the forced outage hours, related to equipment, safety or public health requirements;

and average power level is with a view to optimize high investment costs (nuclear power plants are, as a rule, operated at full power level — this is surely not valid for other baseload technologies such as coal or gas).

The SMRs, designed with unique technological solutions, can have longer fuel cycles, increasing plant availability with a consequent reduction in the specific O&M annual costs in $/MW·h. This benefit is not accessible to LRs.

VI–4.2.4. Technical and design savings

The safety by design approach, described in Section VI–4.1, can also provide advantages in the O&M costs. At this stage, the nature and role of standardization still have to be analysed and modelled in detail, as is the case with capital cost.

Considering other non-differential factors, the O&M cost structure, which includes mainly labour or labour related costs, depends on the wage policies (according to the existing laws that are country specific). Therefore, the plant location is particularly important for the total O&M cost of a plant, but not as relevant for the relative evaluation of SMRs versus LRs.

Another factor important for cost analysis is related to plant age, which is a controversial issue [VI–32 to VI–39]. Some of the operators argue that plant O&M costs dramatically grow after a 'break-in' point located at the very end of the planned lifetime, when the major components begin to fail. On the other hand, some critics argue that the ageing process begins early in a plant lifetime, and can be observed over most of its life. Actually, even an old plant, with the replacement of its vital components (e.g. steam generators), may mask its age and perform like a new one. In any case, the age of a plant is not an important parameter for the relative assessment of different new plants of the same design lifetime.

Considering all of the variables, the O&M cost function can be expressed as:

$$\text{O\&M cost}\left(\frac{\$}{\text{MW}\cdot\text{h}}\right)=f\left\{p(\$/\text{kW(e)}),q(\text{CF})\right\} \tag{VI–9}$$

where

$$p(\$\,/\,\text{kW(e)}=g\ (\text{size, units number, reactor type, ...}); \tag{VI–10}$$

and $q(\text{CF})=h\ (\text{planned outage hours, forced outage hours})$.

VI–4.3. Fuel cycle cost model

The third part of the generation cost model includes an evaluation of the fuel cost for nuclear power plants. The fuel costs represent about 10–15% of the LUEC [VI–5, VI–32, VI–40]. The operations associated with the nuclear fuel cycle typically extend to a period ranging from 50 to 100 years, from mining the uranium ore to finally disposing of the high level waste [VI–41]. The nuclear fuel cycle can be divided into three stages: front end, at-reactor and back end. These, in turn, can be subdivided into more specific components [VI–42].

The front end of the fuel cycle consists of the first four steps: uranium purchase (from mining or milling), conversion to uranium hexafluoride, enrichment and fuel fabrication. The at-reactor stage covers the use of fresh fuel assemblies in the core where the pellets remain from 3 to 5 years, depending on the selected refuelling scheme. For an appropriate cost evaluation, two back end options should be considered. The first is based on early reprocessing of the spent fuel and the recycling of the recovered uranium and plutonium (closed fuel cycle), while the second option is based on long term storage followed by direct disposal (open cycle).

As far as the evaluation of a new nuclear power plant investment is concerned, it seems appropriate to perform a more detailed analysis on the two major fuel cycle cost accounts, i.e. the uranium purchase and the enrichment cost.

VI–4.3.1. Uranium markets

Depending on the prices, uranium purchase can make a large contribution to the total fuel cost of a plant. Uranium spot prices apply to marginal trading from day to day, and usually represent less than 20% of the supply. Most of the trade is 3–7 year long term contracts, with the producers selling directly to utilities. The prices are often related to the spot price [VI–43]. Thus, particular attention has to be paid to the volatility of the price, which, in part, depends on the market environment and the demand–supply situation [VI–41].

VI–4.3.2. Enrichment costs

The mass separation of ^{235}U from ^{238}U can be carried out using many different technologies, such as gas diffusion, gas centrifuges, jet nozzle/aerodynamic separation and electromagnetic isotope separation. The process of laser separation is also under development [VI–44]. As each process requires a specific amount of energy, and depending on the available technology, the enrichment cost varies. Apart from that, the enrichment cost is mainly defined by the ^{235}U percentage in the enriched fuel; the higher the ^{235}U percentage, the more expensive the enrichment. Therefore, SMRs are often designed to have a slightly higher ratio of ^{235}U to ^{238}U compared to LRs.

Considering the impact of fuel cycle cost on the competitiveness of SMRs, some conclusions can be drawn as follows:

- All fuel cycle cost accounts, except the enrichment cost, are generally common between SMRs and LRs. As some SMRs are being designed to use fuel with higher uranium enrichment, useful information could be obtained via a more detailed analysis of the specific uranium cost in \$/kg versus enrichment percentage.
- The fuel cycle cost accounts would be significantly different if the scope of the analysis includes evaluation of the competitiveness of an SMR with other baseload technologies, such as coal or gas.

VI–4.4. Decommissioning cost model

The process of dismantling of a nuclear power plant, called decommissioning, is necessary because radiation hazards remain, even after removal of the plant's fuel. Therefore, the purpose here is to investigate the costs connected with decommissioning.

From a general point of view, the mainframe structure to evaluate decommissioning costs consists of the following six cost groups [VI–45]:

(a) Preparation and project management: This includes all activities carried out during preparation and management of the actual decommissioning.
(b) Facility shutdown: This covers all activities related to the shutdown of a facility.
(c) Decontamination and dismantling operations: This covers all activities related to the decontamination and dismantling operations.
(d) Waste processing and management: This includes all activities related to the treatment, processing, packaging and temporary storage of the decommissioning wastes.
(e) Site restoration: This covers all activities related to the residual radiological characterizations and site restoration.
(f) Other activities resulting in costs that cannot be classified into the groups mentioned above.

In order to evaluate decommissioning costs, many aspects considered for the capital cost would apply. This consideration is consistent, in particular, with the OECD Nuclear Energy Agency study [VI–46], indicating the 14 main cost drivers influencing the decommissioning cost. Considering the main goal of the open model, the cost drivers are divided into two groups. One group is for the activities and costs affecting the evaluation of SMRs versus LRs, and the other group is common to SMRs and LRs (see Table VI–7). Certain elements of this structure are briefly discussed below.

TABLE VI–7. OECD NUCLEAR ENERGY AGENCY COST DRIVERS, ACCORDING TO THE MODEL SCOPE

Differential factors: SMRs versus LRs	Common factors
Reactor type	Scope of decommissioning activities
Reactor size	Decommissioning strategy options
Number of units on the site	Site reuse
Operation history	Clearance and classification levels
Amount of waste	Regulatory standards
Availability of radioactive	Uncertainties and uncertainty treatment
Waste repositories	Labour costs
	Social and political factors

Note: LR: large reactor; SMR: small and medium sized reactor.

VI–4.4.1. Reactor type

Reactor types influence the decommissioning costs because there are significant physical differences between them. For example, the specific geometrical dimension of a light water reactor is smaller than that of a high temperature gas cooled reactor; BWRs have contaminated steam turbines, which is not the case with reactors of other types, etc.

VI–4.4.2. Reactor size — economies of scale

Reactor size defines the quantity and the nature of the radioactive waste that results from decommissioning, as well as the scale of the dismantling required. The considerations of the economies of scale that have already been presented are applicable.

VI–4.4.3. Number of units on the site — learning economies and co-siting economies

All considerations provided for the capital cost also apply to the decommissioning. Experience is essential in order to reduce the risks and costs. This embraces the adoption of a definitive strategy, the necessary planning and preparation, setting up of the right organizations with well defined responsibilities and knowledge of the correct technology for the job and with access to appropriate experts. As an example, the British Nuclear Fuel approach is to set up a dedicated and experienced decommissioning project team. The team is headed by a project manager who is responsible for all decommissioning work on the site and who reports to the plant manager, who is the client and retains responsibility for all regulatory and site safety issues [VI–47].

VI–4.4.4. Operation history

The operation history might have an impact on decommissioning for the following three reasons:

(a) In the case of an incident involving fuel damage or contamination spread, an extensive additional decommissioning effort would be required;
(b) Incidents such as fuel leakage or water chemistry events result in the dispersion of alpha emitting radionuclides within the primary circuit, and this makes the decommissioning and dismantling process more complicated;
(c) The lifetime operating load factor of a reactor influences the radioactivity level.

A safer reactor (as many SMRs might be) can drastically reduce the risks of events using the concept of safety by design. Such an approach is to physically prevent the accidents from occurring rather than deal with their consequences via active or passive means.

VI–4.4.5. Amount of waste

The quantity and quality of radioactive waste resulting from decommissioning may vary significantly among reactor designs of different type. In particular, SMRs seem to produce a lower amount of waste. For instance, considering the IRIS case: "… The reactor vessel can act as a sarcophagus for the reactor internals (the irradiated internals, after defueling, can be left inside the vessel). This greatly simplifies the decommissioning and transportation" and the design provides "…sufficient gamma shielding to reduce the dose outside the vessel from activated internals (barrel, lower support plate). This makes easier and more economical periodic in-service inspections, final decommissioning and disposal" [VI–48].

VI–4.4.6. Availability of radioactive waste repositories

Decommissioning produces significant quantities and different types of radioactive waste that ultimately requires disposal in a suitable repository. Some repositories could be able to accommodate large packages, including whole reactor vessels. Smaller repositories would only accept much smaller packages. These will affect the extent of dismantling and packaging work and associated costs. For SMRs, which are generally smaller in terms of the overall dimensions and components (modules), it seems reasonable to assume that more suitable repositories would be available.

The OECD Nuclear Energy Agency reports cost estimates of 53 reactors, with sizes ranging from less than 10 MW(e) to more than 1000 MW(e). In order to assess the decommissioning cost of a generic nuclear power plant, a database such as PRICE [VI–49] can be used. PRICE presents a hierarchical approach that can be used to identify costs in the key areas. Estimates are produced at various stages in the life cycle of a decommissioning project, based on strategic planning and implementation of the decommissioning.

The task of evaluating the decommissioning cost estimate is not a simple one. Only 5 reactors have been completely decommissioned, while 22 are under way; hence, a historical database of real costs has not yet been established. Moreover, the ex-post cost verification can be 20–70% higher than the ex-ante cost evaluation. However, a reliable estimate is essential for the decommissioning cost, as funds have to be built up during the operational phase of the facility. In fact, in nearly all countries, the operator/utility is responsible for the decommissioning costs. In cases where nuclear power plants are State owned, the responsibilities may be distributed between the operator and the State as an owner.

In the United Kingdom, the Government was directly responsible only for the decommissioning liabilities of non-commercial reactors, owned by the United Kingdom Atomic Energy Authority, but there have been plans for management of future nuclear liabilities.

In Switzerland, the owners of nuclear facilities are required to make financial contributions to a joint decommissioning fund, which is under the supervision of the Government. The board of the joint fund is responsible for ensuring that the contributions are adequate to cover the decommissioning costs [VI–46]. In the USA, almost all utility owners and licensees have collected fees from their electricity customers, over the lifetime of the plant, and deposited these fees in separate funds managed by external financial managers to finance decommissioning [VI–50].

VI–5. THE REVENUE MODEL

Output: Total revenues multiplied by the series over the plant lifetime (input to the investment model).

Inputs: Reactor technology (LRs versus SMRs), reactor cogeneration capabilities, plant size and typical load and service factors, front end investment (output of the generation cost model) and country specific national grid infrastructure.

Parameters/forecasts: Electricity consumption and its spatial distribution (levels, growth rates, variance/standard deviation); wholesale electricity price and/or market structure (installed capacity, reserve margin and supply mix, concentration indices and market shares, spot power exchange versus long term bilateral contracts, etc.); consumption and price for other cogenerated products.

Note: The parameters (and forecasts over the economic lifetime of the plant) should be derived from existing ancillary models and outlooks; they are country specific, and common to LRs and SMRs.

This module aims at modelling, to a certain extent, the electricity market of a country to be analysed. Given the complexity of a detailed model, the simulation of a domestic, competitive (not regulated) electricity market and its outcomes (price and supplied quantity) is beyond the scope of this effort. Some existing models of the wholesale markets for electricity and other cogenerated products can be adopted and integrated.

First, the ancillary models and outlooks are expected to provide plant lifetime forecasts of the country specific variables, which are common to SMRs and LRs, and are appropriate for the revenue model. These are:

- Consumption of electricity (MW·h) at regional, national and local levels over the economic lifetime of the plant. The forecasts offered by the yearly electricity outlooks produced by the International Energy Agency or the US Energy Information Administration (EIA), such as Electricity Information, World Energy Outlook or International Energy Outlook, can be referred to. Alternatively, existing macroeconometric models that estimate the relationship between economic growth and electricity consumption from the public domain economic literature can be integrated (see Ref. [VI–51] on energy consumption and economic growth and Refs [VI–52 to VI–54], among others).

- Wholesale market price for electricity (e.g. €/MW·h) over the economic lifetime of a plant. Given the typical nuclear power plant time horizon, long term price parameters and forecasts rather than short or medium term ones are necessary. Therefore, it is worth refraining from a time series black box approach. One can also include parametric country specific price trends (decrease/increase rates and variance) and carry out sensitivity analyses. These can then be calibrated through expert opinion and public domain outlooks. The existing models of the wholesale electricity markets can also be integrated, for example, those addressing energy market drivers.
- The market structure drivers (total installed capacity, reserve margin, supply mix, concentration indices and market shares, spot power exchange versus long term bilateral contracts, etc.). The revenue model would elaborate the market structure variables and demand estimates to obtain the electricity price evaluations. A computational approach that reflects the market structure and the rules and conducts of national producers is described in Ref. [VI–55]. One can also use the long term electricity market simulator developed for the spot Italian market [VI–56, VI–57] or the electricity pricing module of the national energy modelling system of the US EIA [VI–58].

Finally, some simpler short and medium term models are also worth being surveyed, in order to understand whether their adaptation to a longer term horizon is possible. A similar day or typical day approach allows selection of the historical days closer in behaviour to those under forecasting. The system allows a high degree of configuration options for typical day parameters, e.g. season and climatic data. It is considered a reliable outlook system when a historical dataset is available and the required data are not very far in the time domain. It is reliable, even in the case when auxiliary data are not available at all. It is adopted for short term estimations (10 days), but it can be used for a preliminary estimation of the medium and long term, if the historical data of the previous 18–24 months are available and the forecasting of climatic data is available. The linear regression statistical method can also be applied when only a limited dataset is available. It offers good results when the data on environment and temperature are available for market estimation. Other models are based on autoregressive moving average methods. These models produce the estimation series as a linear combination of the historical supply profiles and the profile of historical errors in past estimations [VI–59].

Once the appropriate ancillary models and outlooks have been identified, and their integration has been proven feasible, the revenue module can import, from these models, plant lifetime forecasts for the country specific variables common to LRs and SMRs. Then, the module should focus only on those factors that are relevant to relative revenues of the SMRs.

The output of the revenue model is total revenues at the plant level over the economic plant lifetime (i.e. estimates of the total inward cash flows). The revenue R (€) is a function of the country or local level electricity consumption Q (MW·h), the market price p (€/MW·h) (or market structure drivers, **MS**), the plant size S (MW), the specific reactor technology T (e.g. whether it is an LR or an SMR) and a set **Y** of other variables:

$$R = R(Q, p \text{ or } \mathbf{MS}, S, T, \mathbf{Y}) \tag{VI–11}$$

The **Y** inputs include the load factors, the national electrical grid and the front end investments. These variables, given the plant size S, the reactor technology R and the national or local consumption estimates Q (which are provided by the ancillary models and outlooks), allow the revenue component to work out an estimate of electricity quantities supplied by the plant (an intermediary variable q). Revenues are then computed as the product of plant electricity supply (q) and wholesale electricity price, which can be either directly offered by the ancillary models and outlooks (p) or elaborated by the revenue model, given the market structure drivers **MS**.

Other revenues from non-electrical products, e.g. hydrogen, desalinated water [VI–60] and district heating [VI–61], can be added to the electricity revenues, given the selected nuclear power plant technology (i.e. T), its cogeneration capabilities (to be included in the **Y** input vector), and price and consumption estimates for cogenerated products (which should be provided by ancillary outlooks and models).

In order to gauge the role played by the **Y** variables (in particular, the reactor technology, the plant size and load factors, the national electrical grid and the front end investments) in determining the plant level quantity of supplied electricity, the departure point is the SMR market matching ability and suitability implied by the scalability, flexibility, easier plant grid matching, and reduced entry barriers, as discussed in Section VI–1.

First, shorter construction times and smaller sizes provide SMRs with more flexibility in incremental addition of capacity compared to LRs. This could be the origin of benefits under both certain and uncertain market conditions [VI–62, VI–63]. In particular, under steady demand and price trends, the SMR scalability allows: (i) to defer the investments and to save financial costs, if the demand growth rate is low; (ii) to stagger the investments and not to lose early revenues, if the demand growth rate is medium; and (iii) to anticipate the investments (and to better define the financial costs) that are yet to reap the anticipated revenues, if the demand growth rate is high. Under highly uncertain market conditions, the SMR reversibility allows the investors to save sunk costs and to reap the revenues.[5]

Second, new investments in SMRs (compared to those in LRs) could be more suitable for those countries where transmission grids are incipient, constrained or fragmented. In such cases, the easier grid matching by SMRs would allow the investors to reap revenues that would be foregone otherwise.

Another entry barrier to nuclear power is the huge size of the front end investments for LRs. These could undermine the entry ability for quite a number of small to medium scale investors. The smaller front end investments for SMRs would then allow these categories of investors to reap revenues.

At this stage of the research, the nature and role of the independent variables in Eq. (VI–11) have still to be analytically represented. In general terms, and similar to the analytical approach described in Section VI–4 for the generation cost model, it would be of interest to determine the differential contributions of individual inputs to the revenues. In particular, the elasticity of revenues to individual *Y* variables for a specific nuclear power plant technology should be obtained (TR is elasticity of revenues):

$$n_T^Y = \frac{\partial \mathrm{TR}/\mathrm{TR}}{\partial Y/Y}\bigg\|_T \qquad \text{(VI–12)}$$

VI–6. THE FINANCIAL COST MODEL

Output: Weighted average cost of capital (input to the investment model).

Inputs: Investor specific equity and front end investment (output of the generation cost module), financial gearing (debt:equity ratio), project and external risk estimates (output of the external cost module).

Parameters/forecasts: Risk adjusted rate of return required by shareholders (risk free rate, market risk premium, data of industrial assets), risk adjusted interest rates required by debt holders (risk free rate, spread on risk free rate) and inflation rate.

Note: The parameters (and forecasts over the economic plant lifetime) should be derived from pre-existing ancillary models and outlooks; they are country specific and common to LRs and SMRs.

The module evaluates the cost of the capital for those private or governmental investors who are planning to build and operate new nuclear power plants. The cost of each source of financing is weighted through the following weighted average cost of capital (WACC), Eq. (VI–13), in a post-tax approach:

$$\mathrm{WACC} = K_{\mathrm{e}}\frac{E}{D+E} + K_{\mathrm{d}}(1-t)\frac{D}{D+E} \qquad \text{(VI–13)}$$

where the necessary inputs are:

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[5] As discussed in Section VI–4, overcapitalization with slack capacity is quite typical of the electrical utilities that have adopted LRs. This may well be a signal of the sunken nature of the investments in LRs.

— Equity amount E invested in the project;
— Financial gearing D/E of the project;
— Rate of return required by shareholders for the equity K_e;
— Interest rate required by debt holders K_d;
— Tax rate t.

The cost of capital is a critical parameter for the economic appraisal of a particular investment. Sensitivity analysis shows its dramatic impact on the values of the financial performance indices. It is included, at a discounted rate, in actualization of the expected cash flows in the NPV calculations and affects the LUEC evaluation through the amortization factor of the constant cost annuities, etc.

In particular, the cost of debt defines the financial interest costs, which are a significant cost item. The interest during construction and the interest on residual debt after commercial deployment of the plant need to be included, as they have a significant impact on the unit generation costs.

Several sources of financing can be employed in a technology and capital intensive project, and each source of financing has its specific cost, set as a minimum rate of return required by each stakeholder to invest in the project.

Investors can be classified into categories of shareholders and lenders, and again in terms of private or public investors:

(a) Private funds can be provided by industrial companies (power companies and utilities), by structured/project financing divisions of the banks or by private equity funds specializing in renewable energy. Institutional investor communities (pension fund managers, etc.) are also becoming increasingly interested in renewables, through specialized long term funding. However, it can be assumed that they do not invest at the level of individual project activities on the ground.
(b) Public funds, such as project development grants and public owned equity funds.

The cost of capital depends on the financial risk perceived by the investor.

Construction and deployment of a new nuclear power plant is associated with high risk factors and sector specific criticalities upstream and downstream of the process. These criticalities are related to the duration and outcome of the licensing, uncertainties in innovative technology, social acceptance, political climate, costs and liabilities of the D&D, waste treatment and disposal, etc.

They are made more important by the capital intensive nature of the project itself, as well as by the very long lifetime of the project compared to other industrial technologies.

In some cases, private stakeholders of a project are able to build innovative and efficient investment schemes to lower the financial/industrial risk. Here, it is worth recalling the construction project of a 1600 MW(e) European Power Reactor at Olkiluoto, Finland, where the shareholders include electricity producers, distributors and industrial users, in a sort of a consortium where the absorption of the entire electricity production is assured at a fixed price through long term sale contracts. Low price electricity would be supplied in exchange for the equity invested. Moreover, the reduced financial risk of the project on its revenue side translates into a lower interest rate required by lenders.

In a more general case, corresponding to free and competitive industrial and financial markets, the risks of a nuclear power plant project may be perceived as unacceptable by private investors or acceptable at an unrealistic investment yield required to cover them, thus resulting in an out of market unit generation cost. Then, the opportunity of public support to a nuclear power plant project becomes important; such support may be provided in different forms (see Table VI–8), in accordance with international (e.g. an OECD agreement), European (for the intra-community contracts) and national regulations.

Public direct financial participation contributes to ease the financial distress of the project, while public indirect support aims to cap the financial liability of the private investors and/or bring the risk factors down to a limit acceptable to private shareholders and lenders. This is reflected in a higher gearing and/or cost of capital of the project. Compared to private stakeholders, the focus and goals of public investors are not primarily linked to project financial profitability, but rather to social welfare (i.e. related to the development of a strategic industry, or the creation of qualified employment, etc.).

TABLE VI–8. POSSIBLE FORMS OF PUBLIC SUPPORT FOR A NUCLEAR POWER PLANT PROJECT

Direct	Indirect
Co-financing of the project through soft loans	Public guarantee on private lending
Capital grants	Public insurance on export financing
Government taking equity stakes (public–private partnership)	Tax regime: production tax credits (as in the USA); penalties on brown power such as the climate change levy in the United Kingdom Revenue support schemes: renewable portfolio standards with renewable electricity certificate trading; fixed price schemes (feed in tariffs); premium prices (on top of unit sale price) Public financial liability on waste treatment and disposal

The public investor, either a shareholder or a lender in the project, should aim to assess the financial soundness of the investment without burdening the cost of capital with an extra profit requirement.

The literature offers two main views on the cost of public sources of financing:

- The 'financial theory' that identifies the cost of public financing with the risk free rate (profitability of a risk free asset such as, for example, a government bond of the same duration as the project).
- The 'economic theory' that focuses on the social preference rate as the most suitable rate or return for a public investor [VI–64]. This model is also 'aware' of the financial theory.

VI–6.1. Factoring risks into the cost of capital

The country specific interest and the industry specific rate of returns should be evaluated given the risk free rate, the risk premium for equity markets, the equity beta (an indicator that relates the industry specific risks to the market risk premium) and the industry interest rates.

The main risk sources for a nuclear power plant (see Table VI–9) may be identified and classified in the areas of:

- Pure financial risk factors/risk of default;
- Industrial/operational risk factors, stemming from operating and capital cost risk factors, revenue risk factors and external risk factors; some of the latter are outputs from the module for other, external factors.

The exposure to industrial/operational risks is as high as the financial distress of the project, which is usually measured in terms of the gearing, interest coverage ratio and payback time. Risk aversion is increased by the amount of capital invested (either debt or equity), which represents a sunk cost for the entrepreneur in the case of adverse conditions.

The risk perceived by each category of investors (shareholders or lenders) is factored into the cost of the respective financing. In particular, the most credited theory to estimate the rate of return required by shareholders for their investment is the capital asset pricing model, which relates the cost of equity K_e to the risk free rate R_f, the market average risk rate R_m and the β parameter, which represents the risk of a specific industry versus the risk of a balanced market portfolio of the industries:

$$K_e = R_f + \beta_E \times (R_m - R_f) \qquad \text{(VI–14)}$$

The difference ($R_m - R_f$) represents the risk premium required to invest in a project with an average industrial risk.

A stock exchange index return is assumed to represent the market risk rate, and the rate of return of a treasury bond of duration comparable to the project lifetime is assumed to represent the risk free rate. This risk free rate should refer to the country where the nuclear power plant would be based, so as to include the sovereign risk of a country. Sovereign risk is defined as the risk that a government will default on its loans or fail to honour other business commitments due to a change in government or policy [VI–65]. The sovereign risk accounts for external risk factors that are common to all kinds of business, and not only to nuclear technology, and can be measured, e.g. considering euro-denominated sovereign debt yields of a specific country.

TABLE VI–9. RISK FACTORS OF A NUCLEAR POWER PLANT

Financial risk factors	Industrial/operational risk factors		
	Cost (operating and capital) risk factors	Revenue risk factors	External risk factors
Gearing Capital employed Interest coverage ratio Payback time/debt duration	Overnight construction costs overrun Plant failures: cost of repair/substitution Decommissioning costs uncapped Waste disposal liabilities uncapped O&M/fuel costs higher than estimated Design modification during licensing/construction/operation	Construction time overrun kW(e) price trend kW(e) price volatility Revenues from cogenerated products Service factor lower than expected Accident plant seizure Load factor lower than estimated Reduced operational lifetime	Regulatory changes once funds are committed Social acceptance (e.g. NIMBY) Licensing duration and outcome

Note: NIMBY: ‘not in my backyard’; O&M: operation and maintenance.

β is the most critical factor in the K_e estimation. It is calculated as the slope of a linear regression of the dividend adjusted stock returns against the market returns.

For a private company or project or a business unit, a reference can be set by an industry β, based on the assumption that the systematic risk is similar for all businesses in that industry [VI–65].

The industry asset β (unlevered β) should account for the underlying business risk of a project, e.g. the operational risks stemming from the cost and revenue sides and from the external factors mentioned in Table VI–9.

However, it is difficult to represent the risk of a specific nuclear power plant through the industry assets β parameter because the sample of peers selected in the β estimation would not represent a reliable proxy of the specific project characteristics (innovative technology). The sample may run diversified activities in other related or unrelated industries, whose impact on the share volatility could tamper the risk analysis. Industry asset β_A should also account for the external risk factors that are typically industry related and cannot be captured by the sovereign risk. Therefore, nuclear power plant licensing issues, social acceptance of the project and the controversial attitude of a government towards nuclear power generation are relevant.

Equity β_E is obtained from asset β_A through Eq. (VI–15), and catches the project specific financial risk:

$$\beta_E = \beta_A \times (E + D)/E \tag{VI–15}$$

All other aspects being equal, a highly geared project is expected to have a higher financial risk, as the debt holders have a priority claim on cash flows of the project over the equity holders (as shown in Ref. [VI–66], where an analysis for regulated electricity distributors, carried out by the United Kingdom energy regulator, is presented). This results in a higher equity β and a consequent higher cost of the equity.

The cost of debt, set as the interest rate required by the lenders, is defined by the interest spread (risk premium) over a risk free rate. The spread component of the cost of a debt is designed to cover all the project risk factors (operational and financial) for the lenders.

Academic studies attempting to explain corporate bond rates empirically are sparser than for those for equities. Elton et al. [VI–67] found that risk aversion is responsible for most of the bond premium and that the expected default premium was responsible for the rest. Bond rating firms (e.g. Standard & Poor's and Moody's) essentially evaluate the default probability.

The lack of widely accepted models relating the debt premium risk results in the requirement for specific negotiations between shareholders and lenders. The industry bond rating is also not a valid reference for the risk premium estimations, given the scarce data record for the nuclear power industry. However, there is a correlation between the financial distress indices and the risk premium. To estimate the financial soundness of the project, a sort of financial rating may be provided by some key financial indicators, such as the:

- Amount of the loan;
- Gearing of the project;
- Cash flow ratios, including interest coverage ratio and cash flow from operations/debt amortization;
- Debt duration.

In general, the higher the amount of the loan and its duration, the greater the risk aversion of the lenders. In fact, the banks cover their risk of default by investing funds in a balanced mix of uncorrelated industry sectors. In this way, a significant amount of invested capital translates into a high risk exposure for the nuclear or the power generation industry, or to a high technology long term project.

Several studies have produced estimates for the private sector risk adjusted cost of capital. Mackerron et al. [VI–64] showed that it would be not less than the rates of return allowed on the regulatory asset base of the regulated electricity industry, which were set at 6.5% in real terms for a public electricity supplier. A 2–3% premium above this would be reasonable for the market to finance a nuclear plant, or a lower premium of 1% in the long term, if the nuclear programme is already established.

Oxera [VI–68] estimated the interest rates of a debt during construction at 10% and 7.5% after refinancing.

A study conducted by CESI Ricerche [VI–69] identifies a plausible value for the cost of equity and debt in a 12% return rate and a 7% interest rate, respectively.

Higher values were reported by Alemi [VI–70]; the debt and equity return rates were assumed to be 12 and 15%, respectively.

Other sources [VI–4, VI–71] agreed on defining the two cases and the two related discount rates. A 5% discount rate would be appropriate for an LUEC calculation for plants operating under the traditional regulated utility model, where the revenues are guaranteed by the captive markets. A higher discount rate of 10% would better apply for a riskier deregulated market or merchant plant environment, where the plant must compete with other generation sources. CESI identifies a public supported investment case with a 5% equity rate of return on investment.

The appropriate definition of equity and debt costs for an investment analysis in the nuclear industry remains a matter of judgement. These costs appear quite sensitive to a variety of country specific and time dependent factors (such as the capital market structure and the energy policy), and, therefore, should be determined on the basis of a complex analysis taking into account all of these factors.

VI–6.2. Enhancement factors for SMRs versus LRs

According to their specific features, SMRs and LRs may have different costs of capital, as discussed in Section VI–1. When adequately taken into account, risk enhancement/mitigation factors (expressed in terms of K_d, K_e and the debt:equity ratio) may affect the strategy of a company or government towards SMRs versus an LR project. The important point could be a reduction of the financial costs available through SMR scalability, investment deferral, reversibility and reduced risk premium (see Section VI–1).

Therefore, the financial cost model should integrate risk enhancement/mitigation parameters that are specific to a nuclear project. These can be provided by the external cost module or be derived through expert judgement. At this stage of research, the analytical relationships between the risk factors and the country and industry specific interest rates and rates of return are still to be identified and discussed further. Gross et al. [VI–72] provided some insights into the role of risk in investment decisions in the energy industry.

Several recent works have illustrated the basic WACC model or adapted it to the power industry. These models can be integrated or adapted within the financial cost model. The guidelines by the UBS Investment Bank [VI–65], the capital budgeting model of the national energy modelling system of the US EIA [VI–73] and the analysis for regulated electricity distributors carried out by the United Kingdom energy regulator [VI–66] are relevant.

A comparative analysis could be developed considering LRs versus multiple SMRs with the same total generation capacity on the site. Different scenarios, ranging from optimized staggered construction of SMR modules to a parallel, concentrated construction of all of the SMR modules could be considered.

In the concentrated construction scenario, parallel construction of all SMR modules would cause a loss of the important learning economies during construction and installation, leading to higher overnight construction costs per kW(e) installed for SMRs versus LRs of the same overall capacity. Lower construction time would still have a positive impact through the lower interest during construction and early revenues to relieve financial advantage, but the capital invested may be comparable or even higher than that for an LR option.

Financial enhancement factors, therefore, emerge in a staggered construction scenario, where the scalability of a cluster of SMRs allows a lower average capital employed and a smoother cash flow times the series modules over the construction period. In this scenario, revenue cash flows from already deployed SMRs would represent a financing source for the construction of the subsequent SMRs. This could relieve the financial distress of the project substantially. Moreover, lower lead times for the deployment of each SMR module would account for a lower total interest during construction for all SMR modules.

A reduced sunk cost from the lower upfront investment and better cash flow profile mean a lower financial default risk of an SMR based project against adverse regulatory and external market conditions. This could mitigate the risk perception of both shareholders and lenders.

A more balanced cash flow profile produces a lower financial leverage of the project.

For the cost of equity, it may be argued that the enhancement of the financial gearing of an SMR based project could result in a lower financial risk for the shareholders. This allows a lower rate of return required for the equity financing through a lower equity β.

Nevertheless, from a shareholder's perspective, comparative assessment of a financial performance of the two options cannot be performed unless the same rate of return is set for the equity invested in the two projects. The financial costs of the project are represented by the cost of debt. Here, the financial enhancement of an SMR based scenario may be expressed by the spread component of the cost of debt. The different merit of credit of the two projects would correspond to different risk premiums (spread on a risk free rate).

The financial enhancement of SMRs may result in either a lower cost of debt or a higher gearing bearable by the SMR based project versus an LR project, for a given cost of debt.

In addition to the financial risk enhancement factors, other industrial/operational risk enhancement factors can be identified, based on the specific features of an SMR concept.

Investment flexibility represents a valuable option for the investors facing the price uncertainty that is characteristic of liberalized electricity markets, allowing faster addition of generation capacity in market upturns and lower sunk costs in market adverse changes, where the investment can be staggered/deferred.

Flexibility allows a more aggressive market strategy with a lower entry electricity price than required by an LR, thus reaping additional revenues, see Ref. [VI–63].

Flexibility and market matching capability are of prime importance to cope with the revenue risk factors because nuclear generation technology is a price-taker and a baseload resource dispatched early in the merit order, and, therefore, it is exposed to the revenue fluctuation of the price of electricity, determined by peak load technologies, such as gas and coal.

The higher modularization and modularity allowed by the reduced sizes of the components of an SMR may translate into better standardization of the construction/installation procedures and less ad hoc design modifications, granting better control over the construction time and cost overruns.

The integral design approach and some specific design solutions of certain SMRs are expected to have a positive impact on the extension of plant technical lifetime and on the quality of performance over the lifetime (i.e. high load factors), thus resulting in an extended revenue base compared to that of LRs.

For a given plant size, multiple units ensure higher plant reliability due to lower parallel failure probability, while increased inherent safety features of SMRs account for a higher service factor and, therefore, a lower probability of loss of revenues due to the plant stops. In addition, these features have a positive impact on the probabilistic risk assessment of the plant. A lower scale of the worst accident scenario could allow the reduction of the EPZ for an SMR plant. This may have a positive impact on social acceptance and may increase market opportunities to include the cogeneration capability of the SMRs. Indeed, cogeneration of products/services (e.g. seawater desalination, district/industrial process heating and hydrogen or ethanol production) would benefit from proximity to the users.

A new design strategy for some SMRs providing for a higher degree of design integrity and modularity would lead to an easier, more standardized plant decommissioning and spent fuel management, lowering the risk of cost overruns in this phase where the liability of the plant owner is often not clearly defined and capped.

Factors increasing the industrial soundness of the project could also mitigate the risk perception by investors and, in this way, lower the cost of financing further.

Table VI–10 outlines the risk factors perceived by investors and highlights possible enhancements brought in by the concept of multiple SMRs versus one LR.

TABLE VI–10. RISK FACTORS AND ENHANCEMENT FACTORS FOR SMRs

	Source of risk enhancement for SMRs
Financial risk factors	
Gearing	Scalability: lower financial gearing achieved with staggered construction
Capital employed	Scalability: lower average capital employed with staggered construction and lower financial exposure of the lenders
Interest coverage ratio	Scalability and shorter lead times: more balanced cash flow profile achieved with staggered construction and deployment
PBT/debt duration	Scalability: lower PBT/debt duration in the case of parallel construction No enhancement in the case of staggered construction
Cost (operating and capital) risk factors	
Overnight construction cost overrun	Modularization and modularity: higher standardization and better construction cost control
Plant failures: cost of repair/substitution	Multiple units on a single site: higher availability factor
Decommissioning costs uncapped	New design solutions based on integral and modular approach: easier decommissioning process
Waste disposal liabilities uncapped	New design solutions based on integral and modular approach: easier high level waste management
O&M/fuel costs higher than estimated	No enhancement via SMRs
Design modification during licensing/ construction/operation	Higher degree of standardization: lower ad hoc design modification risks
Revenue risk factors	
Construction time overruns	Modularization and modularity: higher degree of standardization and better construction time control
kW(e) price trend	Scalability and flexibility: better market matching
kW(e) price volatility	Investment flexibility: adaptability to uncertain market conditions
Revenues from cogenerated products	Reduced EPZ and plant size allow user proximity and increase opportunities for cogeneration
Availability factor lower than expected	Multiple units on a single site: higher availability factor, lower risk of a revenue loss

TABLE VI–10. RISK FACTORS AND ENHANCEMENT FACTORS FOR SMRs (cont.)

	Source of risk enhancement for SMRs
Forced plant outages	Multiple units on a single site: higher availability factor, lower risk of a revenue loss
Reduced operational lifetime	New design solutions: higher expected operational lifetime and higher quality of plant performance kept all along the plant lifetime
External risk factors	
Regulatory changes once funds are committed	Scalability: lower sunk cost in the case of any adverse conditions
Social acceptance (NIMBY)	New design solutions: reduced scale of accidents and reduced EPZ
Licensing duration and outcome	Higher degree of standardization may ease and speed up licensing procedures

Note: EPZ: emergency planning zone; NIMBY: ‘not in my backyard’; O&M: operation and maintenance; PBT: payback time; SMR: small and medium sized reactor.

VI–7. THE INVESTMENT MODEL

This module carries out the investment evaluation. The required inputs are:

- Annual cash outflows from the generation cost model and cash inflows from the revenue model;
- Cost of capital estimated by the financial cost model.

The investment model performs a cash flow investment analysis to produce the following key performance indicators:

- NPV;
- Internal rate of return (IRR);
- Payback time (PBT);
- Profitability index (PI);
- LUEC.

Traditionally, economic research on nuclear power generation has focused on generation costs and the LUEC calculation. LUEC is a suitable reference value for comparative assessments of generation technologies, and it is often used to support decision making regarding energy policy.

However, the projects, even if proven as cost effective through the LUEC criterion, may not be undertaken if the estimated financial return is not high enough to secure the market risks faced by private investors. In the competitive, free electricity markets, investment decisions are made by private companies seeking to maximize the return on investments, subject to acceptable levels of risk and regulatory constraints [VI–72].

Studies in 2001 [VI–67] and modelling efforts (e.g. those accomplished with the FINPLAN and DANESS codes) approach the economic attractiveness of an investment, not only from the generation cost point of view, but also from a broader perspective, estimating the profitability indices, such as IRR and PI, and other financial indicators, e.g. NPV.

The investment model described here provides private and public investors with a framework to carry out strategic assessment of the investment in SMRs versus an LR, based on a full set of financial performance indicators. In particular:

- PBT is an important indicator of the financial soundness of an investment project, and is a very sensitive parameter for the nuclear industry. Nuclear power plants have long construction times and high upfront investments, leading to a tight financial distress and typically long debt duration.

- IRR represents an investment recovery rate that can be checked against a minimum, risk adjusted hurdle rate set by the investor, to evaluate the financial attractiveness of a project.

With the presented model, the public body, either as an investor or a policy maker, could assess the financial viability of a direct investment intervention in an industrial project (such as nuclear generation with several SMRs versus an LR based nuclear power plant) in order to ensure sound employment of public funds and the best economically effective strategy. Alternatively, a check of the efficacy of the adopted regulatory environment against the final investment criteria adopted by the private investors could be performed.

VI–8. THE EXTERNAL FACTORS MODEL

A complete analysis should include not only the quantitative parameters directly linked to the costs and revenues, but also the additional external factors affecting the evaluation of an investment.

The external factors may be (but are not limited to):

- Risks posed by a change in the licensing rules/process and, in general, derived from political crises;
- The environmental laws (e.g. carbon tax, local emission constraints);
- A strategic security of supply;
- The degree of proliferation resistance;
- The level of physical protection, including that from human actions of a malevolent character;
- A trend in the macroeconomic parameters, such as tax rate or inflation rate;
- The confidence level of social acceptance (which could be enhanced by sound technical solutions such as reduction/elimination of the EPZ).

The quantitative estimation of these parameters is neither straightforward nor linked to the quantitative parameters from the investment model. Therefore, a suitable method for integration of these external factors into the overall assessment of investment attractiveness is required. The analytical hierarchy process (AHP) is able to address the issue of evaluating a global figure of merit for different deployment strategies and technological solutions.

VI–9. THE MULTIATTRIBUTE EVALUATION MODEL

The classical techniques for economic and financial evaluations, especially the discounted cash flow methods based on analysis of the discounted cash flow rates, in some cases, do not present a comprehensive picture of the investment and its real value. They are not able to take into account all of the positive features and benefits of a project, as well as all of the disadvantages. They operate on parameters and variables that are quantitatively expressed, with no possibility to incorporate intangible elements.

The multiattribute or multicriteria techniques (multiple attribute decision making) have been set up to address this specific situation, where a choice within a number of options is to be made, given a set of attributes of different kinds, including those of an intangible nature or those not easily measurable in monetary terms [VI–74 to VI–77].

The AHP is one of the most adopted techniques for this purpose. Therefore, it has been selected for evaluation of the attractiveness of a nuclear power plant project. The method represents an explicit way to quantify the evaluation elements, even if they are not tangible in their nature.

The procedure organizes the evaluation process in a hierarchical way. This allows assignment of a weight to each different attribute/criterion by means of a systematic set of comparative evaluations performed among the pairs of such attributes/criteria [VI–78]. It means that the decision is split into sequential levels, where the first level represents the objective of the evaluation (e.g. project attractiveness), and the second and subsequent levels include the attributes and the subattributes with significant importance for the goal [VI–79]. Each attribute and subattribute can be broken up into a suitable level of detail. The last level belongs to the different options under examination (see Fig. VI–2). The procedure is well structured, compared to other multiattribute techniques, and allows performance of evaluation with a high degree of detail. Moreover, software packages are readily available for decomposition and cross-checking evaluations.

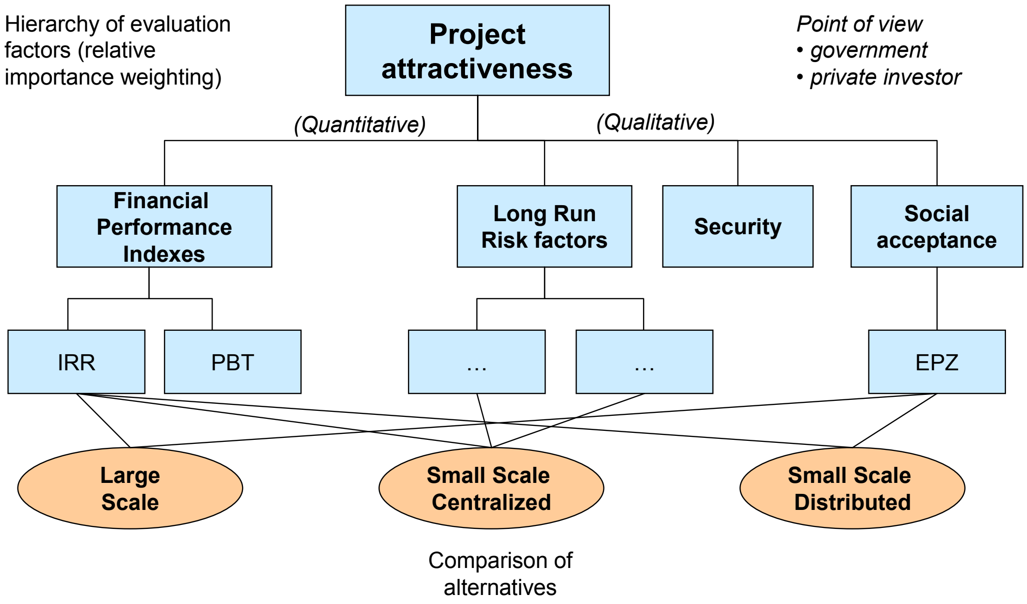

FIG. VI–2. Analytical hierarchy process structure. EPZ: emergency planning zone; IRR: internal rate of return; PBT: payback time.

The AHP allows examination of the options of a project characterized by highly heterogeneous evaluation elements. It is also capable of assessing the sensitivity of the robustness of the final evaluations. When compared to the score models, the AHP is intended for analysis of homogeneous information sets [VI–80, VI–81].

VI–10. CONCLUSION

A framework for the open model of the comparative analysis of investment attractiveness of nuclear energy projects, presented in this annex, is currently being realized as software capable of simulation and evaluation of relative competitiveness features of nuclear power plants with SMRs and LRs for different conditions of deployment and application.

At the time of writing, the software was still at a pre-validation stage. It is anticipated that verified and updated versions of this software will be used in case studies of SMR competitiveness in different applications, carried out in Member States within the IAEA project Common Technology and Issues for SMRs.

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Annex VII

ECONOMIC EXPERIENCE IN CREATION AND OPERATION OF COMMERCIAL PROPULSION NUCLEAR PLANTS

Experimental Design Bureau for Machine Building (OKBM) Afrikantov, Russian Federation

VII–I. INTRODUCTION

This annex considers the reduction of capital costs in commercial nuclear power by employing commercial scale production and common technologies of equipment design and fabrication, based on the vast production and operation experience of Russian Federation nuclear propulsion plants. The performed consideration proves the expediency of adopting the most effective engineering solutions and approaches used for production of propulsion nuclear plants in the production of commercial nuclear power plants.

VII–2. WORLD EXPERIENCE

The experience of those countries that are leaders in stationary nuclear power demonstrates a significant reduction of capital costs owing to standardization, improvement of technologies and increase of labour productivity when unified power units are produced commercially, in series. In France, the reduction of capital costs in construction of standard nuclear power plant units with pressurized water reactors (PWRs) amounts to 20–40% [VII–1]. US experts [VII–2] predict the following rates of capital cost reduction when new nuclear power plants (with reactors of III and III+ generations) are introduced, employing serial production of unified equipment units:

- 35% (reduction of overnight costs) compared with the first of a kind (FOAK) power unit of a new design, owing to the fact that all the following nuclear power plants do not require the same design work as the FOAK, starting from relatively simple conceptual stages and ending with detailed technical data sheets, which help to successfully combine all of the required components. These design costs should never be repeated for *N*th of a kind (NOAK) power plants of this particular design, as design work is mainly focused on arranging the given reactor type at a particular site with specific geographical and geological characteristics.
- 3–10% for each NOAK power plant of the same design, owing to the ‘learning by doing’ effect demonstrated by both suppliers and constructors, and owing to the use of power plant unification advantages (experience with earlier constructed power plants of the same standard design); maximum cost reduction can be achieved in the case of mass construction of several identical power plants at the same site by the same contractor; the effect ends with an asymptotic straight line.
- 15% (reduction of overnight costs) for construction of multiunit nuclear power plants compared with single unit ones, independent of learning by doing effects [VII–3].

VII–3. RUSSIAN EXPERIENCE OF NUCLEAR POWER DEVELOPMENT

One of the most important trends in the history of nuclear power in the Russian Federation (and in the former USSR) is that related to nuclear propulsion plants. A nuclear propulsion plant consists of a reactor plant (RP), a turbine plant, an electrical power system and a complex of control systems. Nuclear propulsion plants can, therefore, be considered as small power analogues of large stationary nuclear power units and close analogues of floating or stationary small and medium sized nuclear power plants.

Development, construction and operation of nuclear propulsion plants were intensive in the former USSR during the 1960s–1990s. At present, the successful operating experience of these plants amounts to more than 8000 reactor-years, which is comparable in order of magnitude to the operating time of all stationary nuclear power units in the world (11 000 reactor-years). The results of life cycle economy analyses of nuclear propulsion plants during their intensive construction and operation in 1963–1992 can be used for creating modern competitive civil nuclear power.

VII–4. RESULTS OF LIFE CYCLE ECONOMY ANALYSES FOR NUCLEAR PROPULSION PLANTS

VII–4.1. Stages of analysis

In 2003–2005, the Experimental Design Bureau for Machine Building (OKBM) analysed the life cycle economy of nuclear propulsion plants. The analysis was performed in three stages, using information provided by major equipment manufacturers, ship building enterprises and dockyards.

The first stage included economic analysis of a serial fabrication of the RP equipment by machine building enterprises. This analysis summarizes the 30 year experience in production of equipment sets for hundreds of RPs [VII–4], with a focus on the economic indicators of serial production of the unified RP equipment lines, including several hundred to several thousand equipment pieces.

The second stage included the analysis of installation of the nuclear propulsion plant equipment and systems at shipbuilding enterprises. The first two stages of the analysis together cover the entire construction cycle of a nuclear propulsion plant, including the design, the pre-production, the production, the delivery, the installation and the tests.

The third stage involved the analysis of operation costs, including service life extension and repair/replacement of equipment. Adequate attention was also paid to the issue of applicability of the obtained nuclear propulsion plant life cycle economy data for commercial scale civil nuclear power.

VII–4.2. Summary of the results: costs

The analysis performed by OKBM revealed certain tendencies in the changes of economic indicators owing to serial production of nuclear propulsion plants. Thus, in the case of serial fabrication of RP equipment sets, their costs can be reduced by 30–35%. The net cost of the installation activities at shipbuilding enterprises can be reduced by 20–40%, with the maximum values being typical for large equipment lines. The reduction is defined by the following factors:

- The use of similar equipment for nuclear propulsion plants of different lines, which increases the overall degree of design unification;
- High production intensity, which ensures continuity of technological processes;
- The use of design and process solutions originally embedded in the equipment and system designs and aimed at cost reduction, such as maximum use of factory assembled units (i.e. delivery of equipment sets as ready to use assemblies) and assembly of RP units at machine building enterprises.

Figure VII–1 illustrates cost reduction for serial fabrication of nuclear propulsion plants.

The stage of operation includes a separate stage of power plant compartment repairs at specialized dockyards; this stage is characterized by the same economic factors and tendencies as the fabrication and installation stages of the nuclear propulsion plant equipment. The average reduction of the repair costs at specialized dockyards is estimated as a minimum of 30%.

VII–4.3. Summary of the results: labour intensity

A reduction of labour intensity during serial production of all types of propulsion plant equipment and systems is a sign of considerable improvement in labour productivity. Labour intensity for fabrication of separate RP equipment items (except for the FOAK pieces) is reduced by two to three times, and the total reduction for the entire set of thermal-mechanical equipment amounts to a minimum of 50% (see Figs VII–2 and VII–3).

Compared to a FOAK plant, the labour intensity for production of a second of a kind nuclear propulsion plant (for which production mastering and pre-production activities are not required) decreases by 15–20% (see Fig. VII–4).

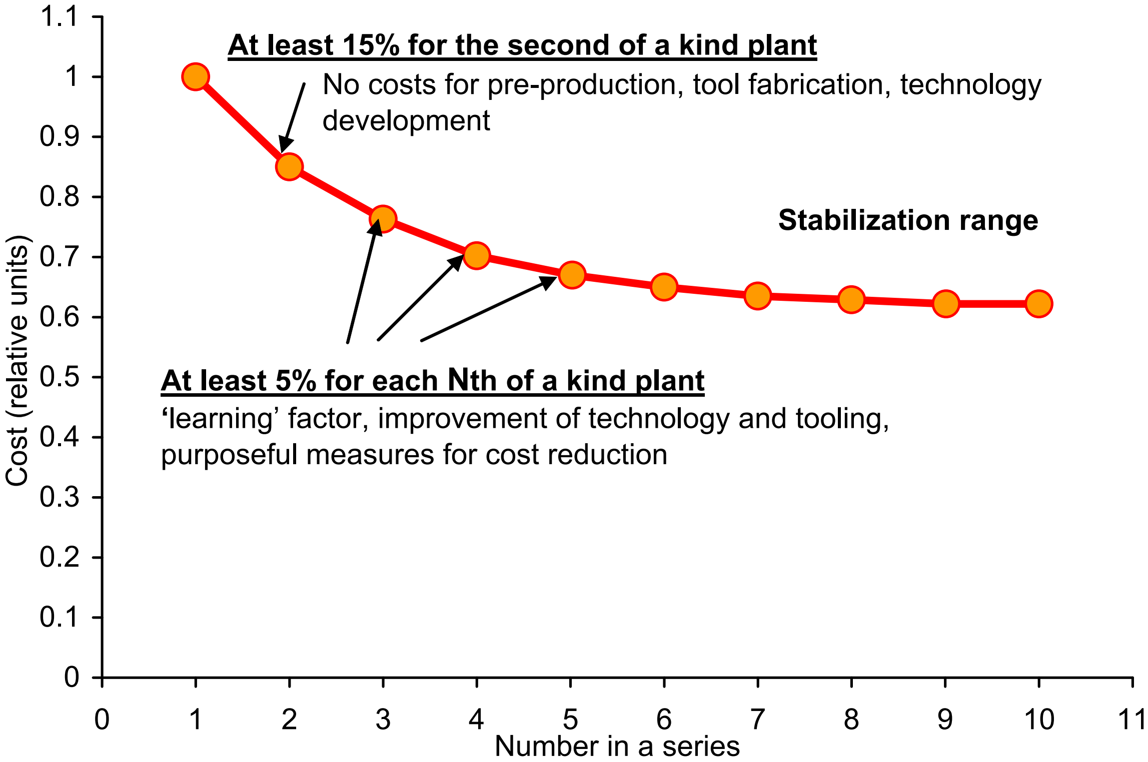

FIG. VII–1. Reduction of actual costs in serial construction of nuclear propulsion plants (equipment fabrication and installation).

FIG. VII–2. Average annual labour intensity for production of primary circuit pumps.

VII–5. FACTORS INFLUENCING COSTS

VII–5.1. Reduction of research and development (R&D) costs

Cost reduction is a major goal at all stages of the life cycle of a nuclear propulsion plant, starting from the very first one: R&D.

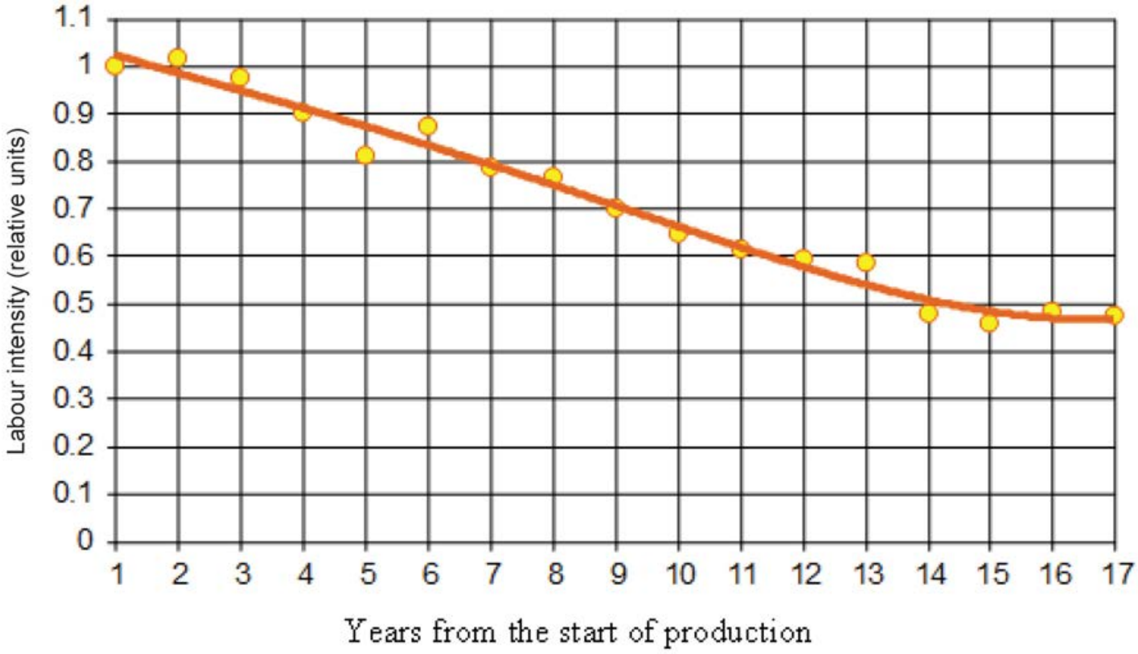

FIG. VII–3. Average annual labour intensity for production of unified reactor plant equipment sets used in various propulsion plant designs.

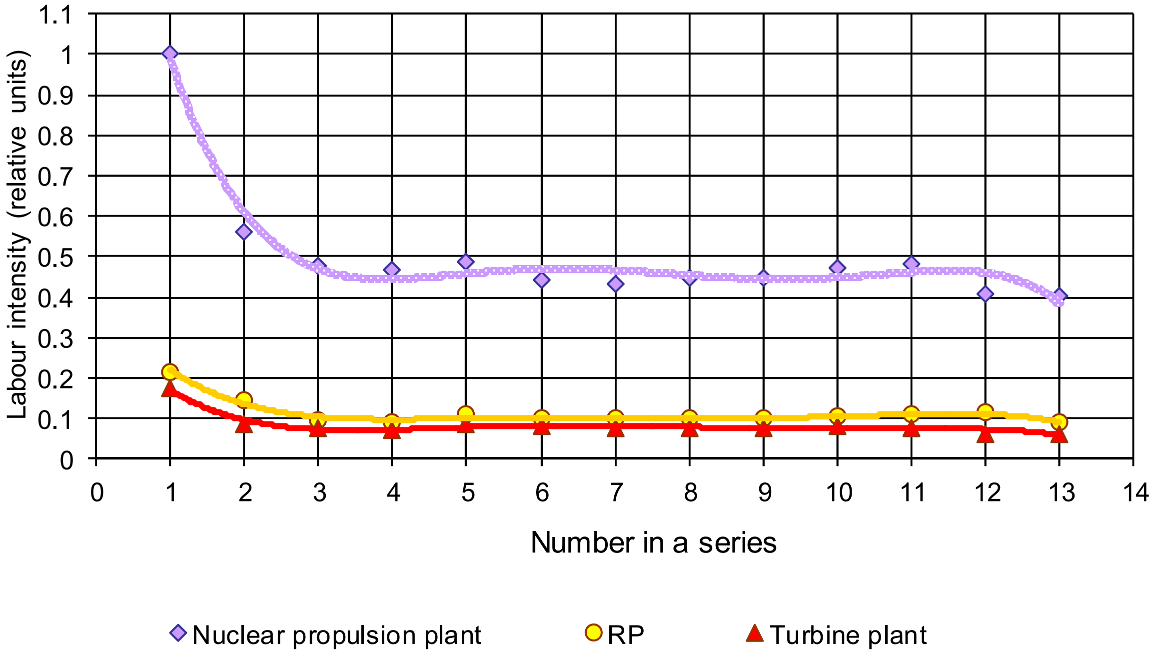

FIG. VII–4. Labour intensity for nuclear power plant equipment and system installation. RP: reactor plant.

The experience of OKBM in research and design of RPs and RP equipment confirms that R&D costs can be reduced owing to:

— Better specialization of design organizations;
— Availability of an inter-industrial or a State programme, and reporting to the customer;
— Use of technical solutions proven in operation, and use of unified items and units;
— Experimental testing of technical solutions on mock-ups, and broad use of mathematical modelling;

- Monitoring of the current state of production facilities, timely development of pre-production work assignments, and maintaining effective ‘feedback’ with production and operation organizations;
- Integration of several design stages;
- Use of computer aided design and other modern techniques for designing and processing of test results.

VII–5.2. Reduction of the costs of commercial fabrication, installation and repair

The following factors help reduce the costs of nuclear propulsion plant fabrication, installation and repair:

(a) The top level factor is State involvement aimed at the fulfilment of the project objectives, observation of the due dates, budget limits and quality assurance requirements. The involvement of the State secures:
  (i) The availability of a programme that specifies the project objectives, the expected results, the work scopes, the schedule, the customers, the participants, the subcontractors, the funding sources, the priorities for delivery and resource allocation, etc.;
  (ii) Comparatively stable centralized funding, tax allowances, etc.;
  (iii) Customer control over the work schedule, scope and delivery;
  (iv) Inter-industrial cooperation.

(b) Industrial factors:
  (i) Specialization of industrial enterprises in fabrication of specific products;
  (ii) Accumulation and analysis of existing experience, improvement of technologies and tools, control methods, etc. by special industrial services and by design, technology and research organizations;
  (iii) Control over labour intensity and policies targeted at labour intensity reduction;
  (iv) Control over work schedules inside one industry;
  (v) Industrial personnel training programmes.

(c) Inter-industrial factors:
  (i) Steady serial production;
  (ii) Modular delivery and installation of equipment;
  (iii) Unification and standardization of technological processes, components, tools, etc.;
  (iv) Continuity of technological processes during fabrication of a batch of serial products;
  (v) Production intensity and output.

VII–5.3. Increase of costs at production stages

Factors conditioning an increase of costs at the stages of nuclear propulsion plant fabrication, installation and repair are, as a rule:

- The arising requirement to improve systems and equipment after launching production of the line, and ‘de-unification’ (see Fig. VII–5);
- Reduction of the production intensity and output, which leads to a discontinuity of the technological processes and creates additional costs for production recovery (see Fig. VII–6);
- Changes in production cooperation patterns, and irregular deliveries;
- Inconsistencies in regulatory documentation;
- Instability of the economic situation in the country and at the enterprises.

VII–6. APPLICABILITY OF THE OBTAINED RESULTS FOR A CIVIL SCALE NUCLEAR POWER PROGRAMME

The Federal target programme Development of the Russian Power Complex in 2007–2010 and until 2015, which is currently being discussed, stipulates intensive serial construction of unified cogeneration nuclear power plants based on 1100–1200 MW(e) water cooled, water moderated power reactors. There are also programmes for the construction of small and medium sized nuclear power plants for regional use, and for further development of fast neutron reactors with a closed nuclear fuel cycle.

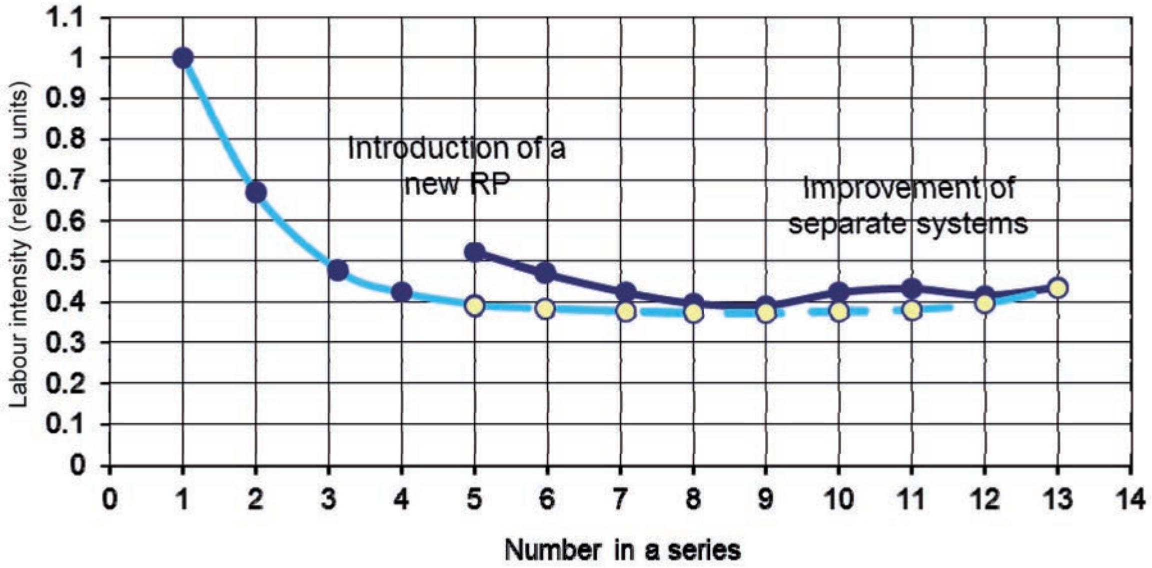

FIG. VII–5. Impact of reactor plant (RP) design modifications on labour intensity of the production of a nuclear propulsion plant.

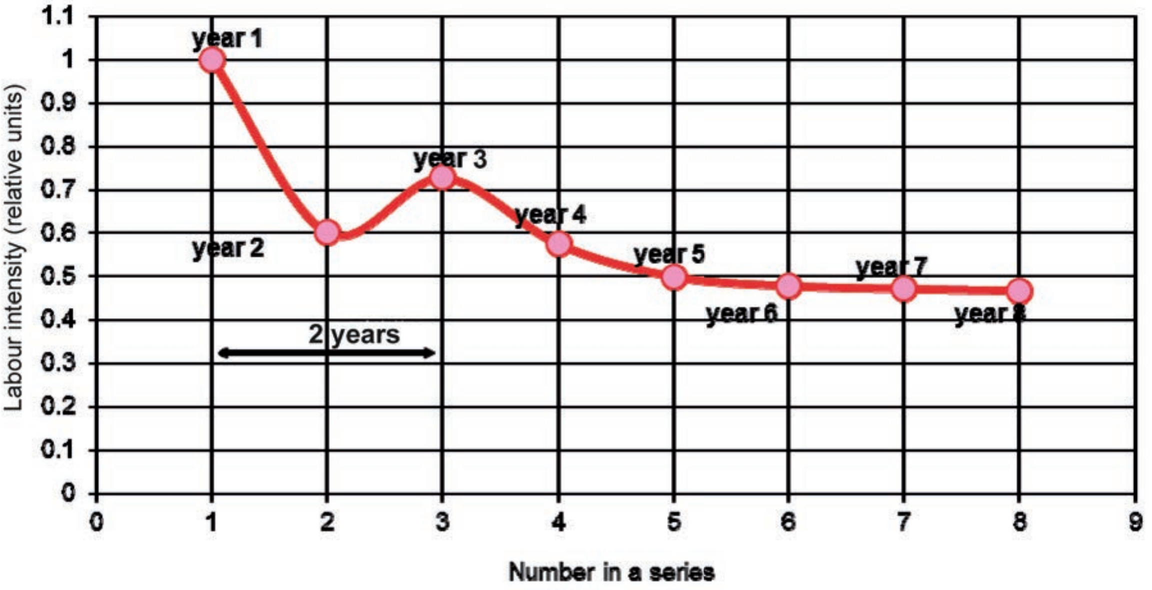

FIG. VII–6. Impact of production process continuity on labour intensity in a reactor plant (RP) installation production (2 year interval after production of the second plant; the third and the fourth plants are produced in the same Argentinian experience year).

All of the above mentioned programmes require an increase in the economic effectiveness of power plants, namely via reducing capital and electricity generation costs.

The results of life cycle economic analyses of nuclear propulsion plants can be applied to Russian civil scale nuclear power because technical principles implemented in propulsion and stationary power plants with PWRs are similar. Although there are certain differences related to the size and the design of these two major types of nuclear power plant, the results of analyses of propulsion plant serial production processes can be applied for serial production of small, medium and large sized nuclear power plants with PWRs.

Studies of a nuclear propulsion plant economy are interesting from the viewpoint of possible borrowing from the most effective nuclear power machine building and shipbuilding practices, centralized power plant compartment repair techniques, and relevant organizational and technical approaches. Such borrowing is applicable mostly to small and medium sized nuclear power plants, both floating and stationary, which are being developed based on the main technical solutions of nuclear propulsion plants. Relevant projects include nuclear power plants with KLT, ABV and VBER RPs developed by OKBM based on shipbuilding technologies with evolutionary cost reduction owing to serial production and unification of the design and technology. Figure VII–7 illustrates possible cost reductions for the construction of a line of floating nuclear power plants.

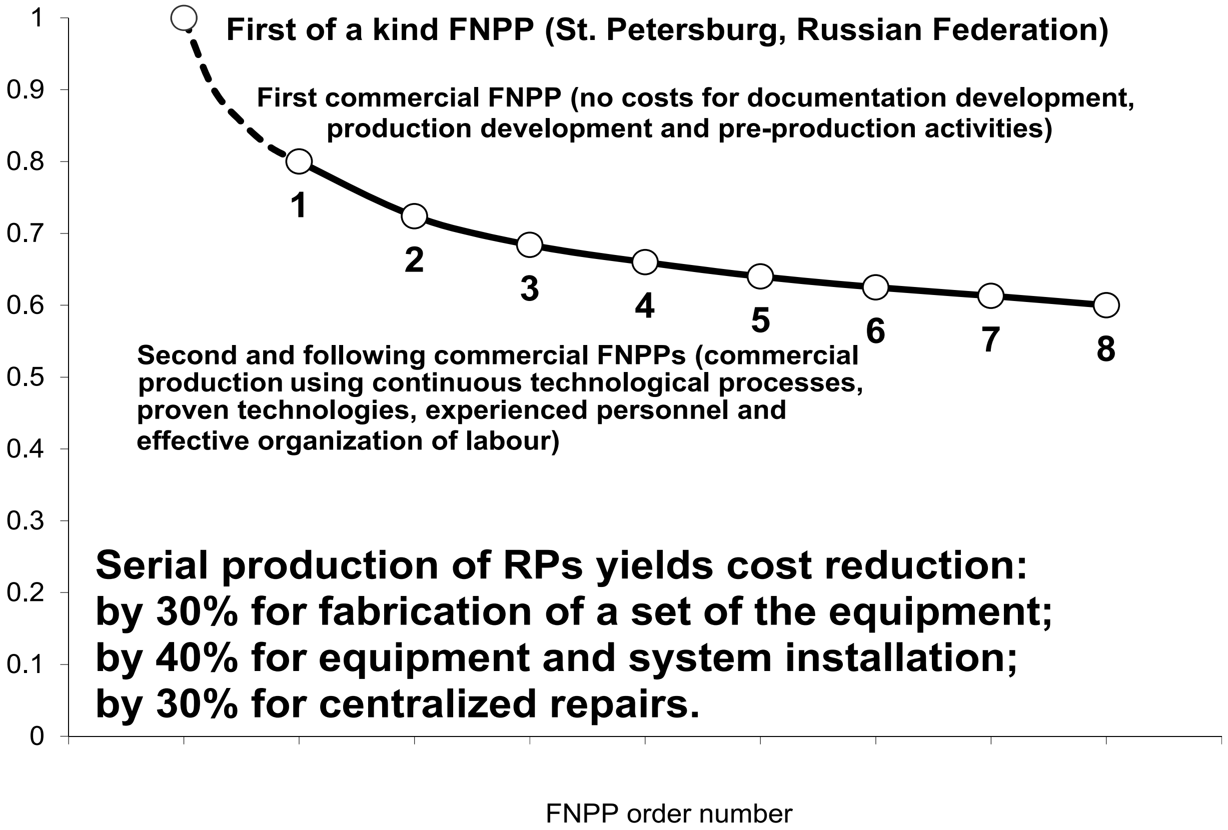

FIG. VII–7. Possible cost reduction for serial production of floating nuclear power plants (FNPPs). The y axis gives costs in relative units. RP: reactor plant.

For near term lines of nuclear power plants, the same economic benefits will be possible owing to the use of unified technical solutions and equipment (especially for plants with twin reactor units); of the results of evolutionary improvement and development of existing designs with acceptable emphasis on available technologies; as well as of production facilities of machine building and shipbuilding enterprises and the established cooperation. In the case of an introduction of radically new design solutions for advanced power plants, which is inevitable with current technological expansion rates, it would be necessary to carry out a thorough analysis of their economic effectiveness.

VII–7. CONCLUSIONS

The results of the performed analysis of serial production of nuclear propulsion plants has shown that serial production of commercial nuclear power plants can lead to a significant reduction of costs at all stages of the power plant life cycle and, accordingly, to a reduction of capital costs and the net cost of generated energy.

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[VII–1] OECD Nuclear Energy Agency, Reduction of Capital Costs of Nuclear Power Plants, OECD/NEA, Paris (2000) 81–82.

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Annex VIII

METHODOLOGIES AND DECISION CRITERIA FOR DEMONSTRATING COMPETITIVENESS OF SMALL AND MEDIUM SIZED REACTORS — PRESENT VALUE CAPITAL COST MODEL

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VIII–1. INTRODUCTION

Smaller size reactors are required to fulfil the growing energy needs of developing countries and emerging markets, as well as niche markets in developed countries. Grid appropriate reactors have been identified within the United States Department of Energy Global Nuclear Energy Partnership initiative as one of the key elements required to enable worldwide expansion of the peaceful use of nuclear power. In a speech at a conference in Algiers on 9 January 2007, the former IAEA Director General, Mohamed El Baradei, discussed the interest in "….new small and medium-size reactor designs which allow a more incremental investment than is required for a big reactor, and provide a better match to grid capacity in many developing countries".

Smaller size reactors (IAEA defines as 'small' those reactors with a power <300 MW(e) and 'medium' with a power <700 MW(e)) are the logical choice for smaller countries or those with a limited electrical grid. In fact, smaller reactors are now in different stages of development throughout the world, and interest in their deployment has also been expressed.

With regards to decisions on the addition of power plant capacity, small reactors have many attractive characteristics, namely size, simplicity, enhanced safety, cost savings and lower financial resource requirements. On the downside, the specific costs of some components and systems of small and medium sized reactors (SMRs) may be higher as a result of economy of scale effects.

This annex explores some of the factors affecting decisions on power plant capacity addition in world markets, focusing particularly on many of the characteristics of SMRs.

VIII–2. SMR CHARACTERISTICS AFFECTING CAPACITY ADDITION DECISIONS

Many of the features of SMRs provide inherent advantages for application within electric generation markets. These advantages range across the areas of plant cost and financing, and fit with utility and country circumstances.

Figure VIII–1 presents the outline of a plant capacity and timing decision model. The three factors influencing the overall decision criteria are (i) cost, (ii) financing, and (iii) utility and country circumstances. The highlighted areas of overnight capital cost (OCC), total capital investment cost (TCIC), present value capital cost (PVCC), capital at risk and cash flow profile have direct influences on cost and financing. A conceptual model of the potential impact of SMRs on these areas is presented below. Additionally, the suitability of SMR characteristics for various utility and country circumstances is addressed. Depending on the specific circumstances of potential customers, different cost–financing–customer circumstances decision criteria trade-offs will be required, resulting in different optimal decisions being made. These are discussed in the following.

VIII–2.1. Cost

Cost savings are available in a number of different areas related to the smaller size of SMRs.

VIII–2.1.1. Multiple units and learning

Since a larger number of SMRs are required to provide the same total plant capacity as a large reactor (LR) plant, savings to overnight cost can be achieved because of multiple unit and learning curve cost savings. Each of the additional units will have an overnight cost lower than the first unit since there are some fixed, non-repeatable costs incurred in the first unit. Other advantages to the deployment of multiple units at a single site are the sharing of infrastructure and better utilization of site material and human resources. These savings reduce the average cost of multiple units built on a single site or on multiple sites within a larger construction programme.

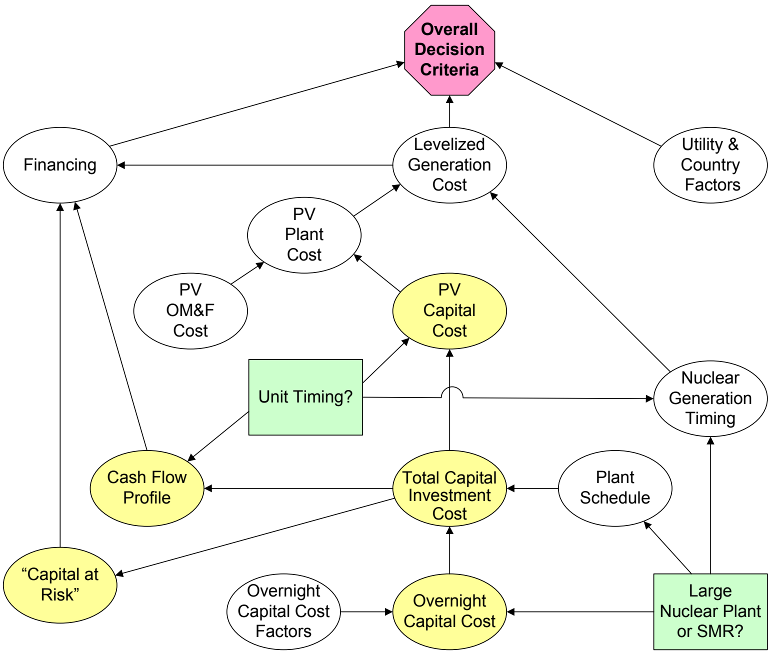

FIG. VIII–1. Outline of a plant capacity and timing decision model. OM&F: operation, maintenance and fuel; PV: present value; SMR: small and medium sized reactor.

Additionally, SMRs are characterized by what can be called economy of replication, based on bulk ordering and serial fabrication of components. To give an example, the 335 MW(e) International Reactor Innovative and Secure (IRIS) module employs eight steam generators versus the two to four steam generators for a large, conventional 1200 MW(e) pressurized water reactor. Thus, production of 6000 MW(e) by IRIS requires the fabrication of 144 steam generators versus 10–20 for an LR plant. The small, simple components of SMRs can be produced on a small scale assembly line rather than one at a time, potentially resulting in lower specific costs.

In addition to multiple unit savings, each unit constructed in a series of SMRs, after the first, will benefit from construction learning that occurs on each site and within a programme of multiple sites. Learning curve savings are obtained from the construction of successive units as a result of more replication and faster progression along the learning curve.

Data on multiple unit and learning savings for series builds of LRs are provided by the nuclear construction programmes in France and South Korea. SMRs permit a greater degree of savings for series builds since a larger number of units are used to achieve a desired level of total capacity.

VIII–2.1.2. Plant design and modularization

Overnight costs can be further reduced to the extent that plant designers are able to achieve more cost efficient designs with design concepts which are currently possible only at smaller power levels. These cost savings can result from (i) simpler, fewer, less complicated components (integral equipment design); (ii) alternative safety system approaches (passive safety system, safety by design); and (iii) a greater degree of modularization and factory fabrication. These cost reductions are specific to individual SMR designs and design concepts.

Simplicity, reduced type and number of components

SMRs are generally new designs that try to simplify existing solutions. Their safety characteristics tend to be enhanced because intrinsic and passive safety is better enabled by the smaller size; enhanced safety, if properly accounted for, translates into a cheaper design.

The smaller size and lower power of SMRs allows them to be more accessible to modularization, i.e. construction and deployment of a larger number of standardized units. Modularization reduces the requirements for more expensive and time consuming on-site construction and also allows more factory fabrication.

In addition to the unit power cost per kW(e), an index based on the amount of required commodities (such as steel and concrete) is also considered in evaluating a reactor plant. Owing to their compactness, the commodities index (m^3/kW) in SMRs is approximately the same as, and in many cases lower than, that in large plants. Another effect of their compact design is that a cluster of SMRs, having the same total power as a large plant, can potentially require less land.

Security

Engineering additions required to enhance security are intrinsically less expensive in SMRs because of their smaller size and simpler design. For example, dispersed SMRs would offer a much smaller target to terrorist controlled aircraft. Their enhanced intrinsic safety and passive systems also decrease the chances of internal sabotage (and, thus, the cost of counteracting measures).

Lifetime

Many SMR designs have the potential for longer lifetimes of both the core and the reactor structures, including the pressure vessel.

VIII–2.1.3. Construction schedule

Smaller physical plant sizes can be constructed with shorter construction schedules. For a given commercial operation date (COD), shorter schedules, with relatively later expenditures closer to the COD, result in lower TCICs because of lower costs for interest during construction.

VIII–2.1.4. Unit timing

Meeting a requirement for power with multiple SMRs built over an appropriate time frame can spread out the capital expenditures over time, and result in much later expenditures than can be achieved by meeting it in one large block. This delay in capital expenditures can substantially reduce the present value cost of the investments involved.

VIII–2.1.5. Economy of scale

Economy of scale will result in an increase in the per kW(e) costs of some components and systems of SMRs relative to LRs where the components and systems are scaled down versions of LR designs. However, as discussed above, SMR designs often eliminate the requirement for the many components and systems needed in LR designs, and many of the remaining components and systems are based on significantly different design concepts and approaches.

VIII–2.2. Financing

Depending on the size and financial circumstances of the plant owner, various financial criteria will assume greater importance among the overall decision factors. Deployment of SMRs can provide significant benefits regarding capital at risk and cash flow profile financial impacts.

VIII–2.2.1. Capital at risk

Lower investment costs and shorter construction schedules for SMRs relative to LR units improve the ability to finance capacity expansion projects. SMR TCICs are in the hundreds of millions of dollars range as opposed to the billions of dollars range for LRs. These smaller investments are more easily financed, especially for countries and utility systems with more limited financial resources. Most emerging and developing countries could simply not afford this magnitude of investment prior to receipt of revenue or the impact the repayment schedule would have on the balance of payments that would be required to construct LR plants. Shorter construction schedules also improve the time to return on investment, further enhancing financial attractiveness.

VIII–2.2.2. Cash flow profile

Smaller capacity increments may provide a better fit with baseload capacity growth for either smaller utility systems or for larger utility systems with lower rates of load growth. Utilizing series builds of SMRs in these circumstances with progressive construction/operation of multiple modules deployed in succession, rather than adding one large block of capacity, allows the earlier reactors to begin operation while others are still being completed. In this situation, substantial revenue is generated before all of the plant investment expenditures are made. This makes it possible to minimize the total net cash outlays for the capacity expansion programme. SMRs, thus, significantly expand the applicability of nuclear power to current and future electricity demands and make it available to those countries and utilities that, until now, would not have considered it as an option.

VIII–2.3. Utility and country circumstances

The relationship of new baseload capacity with utility and country circumstances is another important consideration in the overall decision criteria. SMRs provide a better fit with the local circumstances and resources available in many potential nuclear plant markets. For those situations, the following decision factors may assume increased importance.

VIII–2.3.1. Grid size (electrical grids with limited capacity)

It is a general rule of thumb that a grid should not be subjected to power variations in excess of 10% of the total grid capacity. So, 1000 MW(e) plants cannot be deployed in grids of 10 GW(e) or less. The size of SMRs allows a much closer match of supply to demand than is possible with large plants. This allows better planning, with reductions in the planning margin. In addition, insertion of smaller units reduces the challenge to grid stability. Even in larger interconnected grids, large power additions/subtractions can cause grid instabilities. These instances have been rather common in the last few years, as demonstrated by blackouts in the northern USA/Canada and Italy in 2003, and central Europe in 2006.

VIII–2.3.2. Demand growth (baseload growth for nuclear)

Even for systems that can accept a plant larger than 1 GW(e), a smaller plant may be a better fit with the annual increase in the growth of baseload.

VIII–2.3.3. Central site versus dispersed sites for series builds

SMRs on dispersed sites may be more appropriate for remote areas requiring smaller, localized power centres. They can be located closer to load centres, thus avoiding investments in long and expensive transmission lines, with related transmission losses, required by a central location.

VIII–2.3.4. Geographical relationships

Similarly, geography and demography featuring mid-size urban and power demand areas that are fairly scattered, rather than concentrated in a few mega centres, may benefit from the location of SMRs closer to demand.

VIII–2.3.5. Local construction infrastructure

Smaller, simpler designs of SMRs may provide a better fit with local construction infrastructure resources, and may also provide a greater potential for localization of supply from the existing manufacturing base. The simplicity of the design also increases possibilities for progressive localization depending on the development of local industry. This influences the cost and could possibly be an input for decision making. The smaller size of the components increases the number of potential manufactures in a region than would be available for larger components. Spin-off benefits to the local industry would be a bonus.

VIII–2.3.6. Non-electrical plant applications

Cogeneration (desalination, district heating, industrial steam, process heat) is the province of SMRs. While, in principle, cogeneration is independent of nuclear plant size, in practice, economic considerations have driven the larger plants to be pure producers of electricity, since utilities prefer that the multibillion dollar investment in large nuclear plants produces the highest amount of baseload electricity. In addition to this consideration, there is another factor that makes SMRs the best nuclear plants for cogeneration. Cogeneration can be the production of: fresh water by desalination; steam for district heating, industrial or agricultural application; process heat for the chemical industry; or hydrogen. One common characteristic is that, while electricity can be transported long distances, cogeneration products require close proximity of the producer and end user. Since nuclear plants are licensed with population restrictions (exclusion zones, low population zones, etc.), either significant infrastructure/transport costs are incurred, or cogeneration is simply not possible. As previously mentioned, the safety characteristics of some SMRs may allow them to attain licensing without the requirement for emergency response. One of the designs leading these efforts is IRIS, with objectives to obtain licensing with a collapsed population exclusion zone that will be very close to the plant boundary [VIII–1, VIII–2].

VIII–3. CONCEPTUAL GENERIC MODEL

A generic model has been used to evaluate the relative impact of some SMR cost factors on the new generation capacity decision criteria highlighted in Fig. VIII–1 (OCC, TCIC, PVCC, capital at risk and cash flow profile). These factors are (1) economy of scale, (2) multiple units, (3) learning, (4) construction schedule, (5) unit timing and (6) plant design. Figure VIII–2 illustrates the relationship of these six factors in deriving a comparison of the relative cost per kW(e) of SMRs with that of LRs. This model does not address the impact of customer specific utility and country circumstances on the decision criteria.

Table VIII–1 presents the input assumptions used in determining the nominal case results. The four unit SMR-4 plant is assumed to provide the same total capacity as the single unit LR plant, with each unit at one quarter of the capacity of the LR unit. The scaled large reactor (SLR) cost assumes a hypothetical plant design based entirely on the LR design and scaled to one quarter capacity. The SMR-4 unit timing is assumed to match the load growth, which requires the equivalent of one SMR-4 every 9 months. A representative design cost saving of 15% is assumed as the nominal case for a generic SMR. A discount rate of 5% per year is used for all results.

VIII–3.1. Economy of scale

The first factor represents the economy of scale, assuming that the two plants are comparable in design and characteristics. The usual correlation:

$$\mathrm{OCC}_{\mathrm{SMR}} = \mathrm{OCC}_{\mathrm{LR}} \times \left(\frac{\mathrm{size}_{\mathrm{SMR}}}{\mathrm{size}_{\mathrm{LR}}} \right)^{n-1} \tag{VIII–1}$$

is adopted with $n = 0.6$. This factor determines a hypothetical OCC estimate of a single LR design that is scaled in its entirety to one quarter size. In this case, the OCC per kW(e) of the SLR would be 74% higher than the LR of actual size.

VIII–3.2. Multiple units and learning

The site multiple unit factor is evaluated considering that there are fixed, non-recurring costs only incurred for the first unit and there are costs that are shared by multiple units.

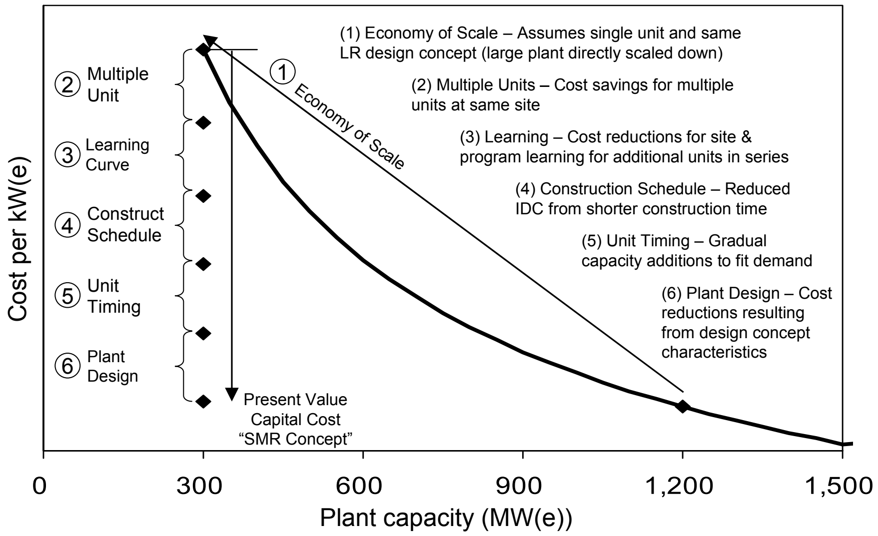

FIG. VIII–2. Potential small and medium sized reactor (SMR) cost factor advantages. IDC: interest during construction; LR: large reactor.

TABLE VIII–1. ASSUMPTIONS FOR MODEL EXAMPLE — NOMINAL CASE

Parameters	Values
SMR-4 to LR size ratio	1:4
SLR cost	Based entirely on LR design scaled to 1:4 ratio
SMR-4 unit timing	Every 9 months
SMR-4 design cost savings	15% assumed savings
Discount rate	5% per year

Note: LR: large reactor; SLR: scaled large reactor; SMR: small and medium sized reactor.

The learning factor considered here is the 'on-site' type factor and is evaluated from the various models reported in the literature (e.g. Generation IV [VIII–3]). It was found that for the four unit case, the cost reduction is between 8 and 10%. The 8% value was conservatively chosen.

The combined impact of multiple units and learning is a 22% reduction in OCC for a four unit SMR-4. This is consistent with Korean and French experience reported in the literature for series builds of multiple units on the same site or multiple sites within the same standard plant programme.

VIII–3.3. Construction schedule

The effect of the construction schedule is evaluated assuming a construction schedule for the LR and SMR of 5 and 3 years, respectively, and calculating the TCIC for the two cases. This shorter construction time results in a 5% saving for SMRs.

VIII–3.4. Unit timing

The LR and the first SMR unit are assumed to go into operation on the same date. The remaining three SMRs are assumed to begin operation every 9 months thereafter. The relatively later capital cost expenditures for the SMR reduce the PVCC by an additional 5% compared to the LR. The unit timing savings on the PVCC increase as the time between units matching load growth is increased. At 24 months, the savings would increase to 12%.

VIII–3.5. Plant design

The level of OCC savings achieved by the application of improved design concepts for SMRs is highly dependent on the specific SMR design and that of the LR reference. The elimination of plant components and systems in combination with more compact plant layouts can result in significant SMR cost reductions.

For this generic analysis, cost savings in the range of 5–30% are included in sensitivity results. A 15% cost saving is assumed for the nominal case.

VIII–3.6. Combined capital cost results

When the various factors are combined (Table VIII–2), a pack of four SMRs has a 16% higher OCC, a 9% higher TCIC and only a 4% higher PVCC than a single LR with the same total capacity. Sensitivity results are contained in Table VIII–3 for design specific capital cost factors ranging from 0.95 (5% OCC savings) to 0.70 (30% OCC savings). These results indicate that SMRs can be an attractive alternative solely on the basis of cost.

TABLE VIII–2. RESULTS OF THE SMR CAPITAL COST FACTOR MODEL

Capital cost factor	Capital cost factor ratio (SMR)		
	Overnight capital cost	Total capital investment cost	Present value capital cost
(1) Economy of scale	1.74	1.74	1.74
(2) Multiple units and (3) Learning	0.78	0.78	0.78
(4) Construction schedule	n.a.	0.94	0.94
(5) Unit timing	n.a.	n.a.	0.95
(6) Design specific	0.85	0.85	0.85
Cumulative total	1.16	1.09	1.04

Note: n.a.: not applicable; SMR: small and medium sized reactor.

VIII–3.7. Capital at risk

Capital at risk becomes a more important decision factor for the circumstances where the total capital invested prior to receipt of revenue is a critical factor for new nuclear capacity financing. For the example input assumptions identified in Table VIII–1, the capital at risk for a single or first unit SMR-4 is only 35% of that for a single unit LR, a significant improvement in ability to finance for many potential nuclear plant customers.

TABLE VIII–3. DESIGN SPECIFIC COST FACTOR SENSITIVITY

Design specific capital cost factor ratio	Cumulative total capital cost factor ratio (four SMRs versus one LR)		
	Overnight capital cost	Total capital investment cost	Present value capital cost
0.95	1.29	1.22	1.16
0.90	1.22	1.15	1.10
0.85	1.16	1.09	1.04
0.80	1.09	1.02	0.98
0.75	1.02	0.96	0.91
0.70	0.95	0.90	0.85

Note: LR: large reactor; SMR: small and medium sized reactor.

VIII–3.8. Cash flow profile

SMRs provide flexibility to manage the cash flow profile. For market circumstances where the maximum net negative cash flow assumes a greater importance in the decision, the adjustment of time between each SMR in a series can be used to minimize this metric. Table VIII–4 presents sensitivity results for net maximum negative cash flow versus time between units. Beyond a certain point, increasing the time between units may trade-off some potential OCC construction learning savings in order to minimize peak cumulative cash flow. For many potential nuclear plant customers, this becomes a worthwhile trade-off.

TABLE VIII–4. MAXIMUM NEGATIVE CASH FLOW (COMPARABLE LR AND SMR CAPACITY)

Time between SMR units (months)	LR value (%)
9	82
12	70
24	41
36	35

Note: LR: large reactor; SMR: small and medium sized reactor.

VIII–3.9. Utility and country considerations

The utility and country circumstances discussed above are not directly addressed in this model. Utility and country specific analyses will be required in order to quantify SMR advantages within the related decision criteria in relation to the advantages addressed above. Through a combination of the decision factors for cost, financing and utility/country considerations, many markets will be identified where SMRs provide the optimal choice for baseload capacity.

VIII–4. SUMMARY AND CONCLUSIONS

This annex has explored the impact of many of the characteristics of SMRs on a range of decision criteria considerations for potential nuclear plant customers including (i) cost, (ii) financing, and (iii) utility and country circumstances. Of the six capital cost factors considered in a conceptual generic model, economy of scale, multiple units, learning and plant design act directly on various portions of the OCC. Shorter SMR construction schedules reduce the required interest during construction and, thereby, the TCIC. A better fit of smaller units with baseload growth requirements further improves the PVCC, reducing the capital portion of SMR generation costs.

Significantly lower capital at risk for SMRs can further enhance the ability to finance new nuclear capacity, as can an improved cash flow profile, which results from optimizing the time between SMRs in series build programmes.

Beyond the impact of a better fit of small reactors with utility size and load growth in many world markets, other aspects of utility and country circumstances, including geographical relationships, local construction infrastructure and non-electrical plant applications, contribute towards favourable decision factors regarding SMR implementation.

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www.gen-4.org

Annex IX

THE G4-ECONS ECONOMIC EVALUATION TOOL FOR GENERATION IV REACTOR SYSTEMS AND ITS PROPOSED APPLICATION TO DELIBERATELY SMALL REACTOR SYSTEMS AND PROPOSED NEW NUCLEAR FUEL CYCLE FACILITIES

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IX–1. INTRODUCTION AND BACKGROUND

At the outset of the international Generation IV programme, it was decided that the six candidate reactor systems will ultimately be evaluated on the basis of safety, sustainability, non-proliferation attributes, technical readiness and projected economics. It is likely that the same factors will influence the evaluation of deliberately small reactor systems[1] and new fuel cycle facilities, such as reprocessing plants that are being considered under the more recent Global Nuclear Energy Partnership (GNEP). This annex describes how the development of an economic modelling system has evolved to address the issue of economic competitiveness for both the Generation IV and GNEP programmes.

In 2004, the Generation IV Economic Modelling Working Group (EMWG) commissioned the development of a Microsoft Excel based model capable of calculating the levelized unit electricity cost (LUEC) in mills/kW·h (1 mill = $\$10^{-3}$) or \$/MW·h for multiple types of reactor system being developed under the Generation IV programme. This overall modelling system is now called the Generation IV spreadsheet calculation of nuclear systems (G4-ECONS), and is being expanded to calculate costs of energy products in addition to electricity, such as hydrogen and desalinated water. A version has also been developed to evaluate the costs of products or services from fuel cycle facilities. The cost estimating methodology and algorithms are explained in detail in the Generation IV Cost Estimating Guidelines [IX–1] and in the G4-ECONS User's Manual [IX–2].

The model was constructed with relatively simple economic algorithms such that it could be used by almost any nation without regard to country specific taxation, cost accounting, depreciation or capital cost recovery methodologies. It was also designed with transparency to the user in mind (i.e. all algorithms and cell contents are visible to the user). A short description of version 1.0 G4-ECONS-R (reactor economics model) has also been published in the Proceedings of the June 2007 Meeting of the American Nuclear Society (ANS) [IX–3]. It is the purpose of this annex to expand upon this ANS summary, which dealt mainly with Generation IV applications, and explain the levelized cost algorithms in more detail in the hope that they can be applied to evaluate GNEP facilities such as grid appropriate reactors, fuel cycle facilities and a demonstration advanced recycle reactor.

IX–2. BASIC MODEL STRUCTURE AND THE CONCEPT OF COST LEVELIZATION

Each section of the reactor economics model computes a component of the total LUEC, which can be divided into four life cycle components: (i) recovery of capital (including financing costs), (ii) non-fuel operation and maintenance (O&M) costs, (iii) fuel cycle costs, and (iv) annual funding of decontamination and decommissioning (D&D) costs via an escrow fund. All costs are calculated on a constant dollar levelized annual cost basis, and it is assumed that capital and financing costs are repaid over the operating life of the plant. Annual electrical production is also considered at a constant value over the life of the plant. Each component of the LUEC is calculated by dividing the annualized cost (million \$/a) for that component by the annual production (kW·h/a). An average capacity factor is also assumed over the life of the plant to relate electrical energy production (plant performance) to the net installed capacity of the plant.

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[1] Deliberately small reactors are also known as grid appropriate reactors. The term small and medium sized reactors is also frequently used for this class of reactors.

Figure IX–1 illustrates the concept of levelization that is central to this type of economic modelling. The left hand side of the figure shows how typical cash flows (million $/a) actually occur over the life cycle of a power plant. During the design/construction phase, annual costs rise to a peak and taper off into the startup phase. Annual O&M and fuel costs are nearly constant (assuming constant dollar costing), with an occasional blip for a major capital replacement item such as a steam generator. At end of life, there is another blip for the D&D of the plant. Power production also has a ramp up and ramp down period. For actual power plant projects, utilities typically use business models where such annual cash flows and annual power production (revenue steam) projections are entered into a complex spreadsheet in order to calculate revenue requirements and project financing requirements. However, for technology comparison purposes, such as Generation IV and GNEP applications, such cash flow models are too complex, and the input data do not exist at a fine enough level of detail to support that business model type of modelling. For this reason, G4-ECONS was designed to treat the costs in the levelized manner shown on the right hand side of Fig. IX–1. Essentially, all front end costs (design, construction, startup and financing) are rolled up into a single total capital cost or total lump sum capital cost (TLCC). This TLCC is then recovered over the life of the plant by means of a capital recovery factor that, in turn, depends on the assumed interest or discount rate. The reverse of the capital recovery algorithm (a sinking fund equation) is used to recover the future D&D cost over the plant's operating life. Other annual costs, such as fuel, non-fuel O&M and capital replacements are calculated or entered into the model as average (typically, million $/a) values that are the same over all years of the operating life. An average assumed power production also has a constant value over the plant's operating life, and represents the revenue to the utility. It is felt that this simpler representation of economics will minimize the amount of data that the project proponents must develop during the research and development phase of the Generation IV and GNEP programmes.

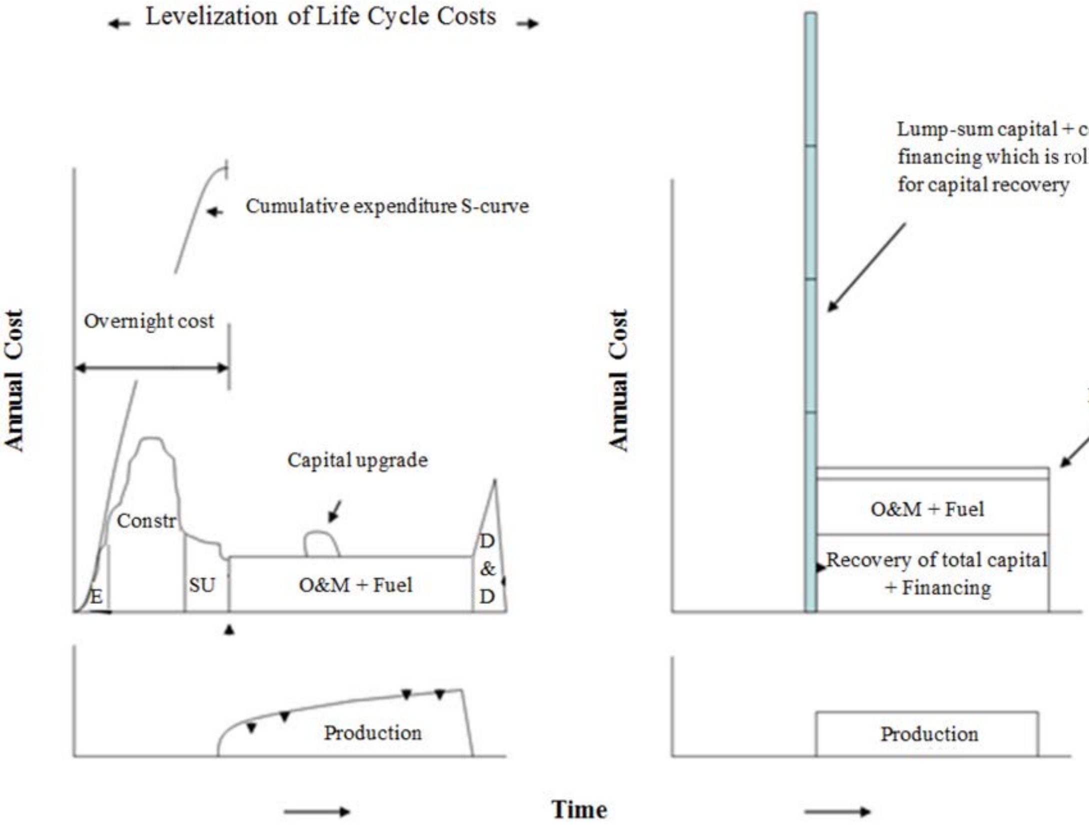


FIG. IX–1. Concept of cost levelization. D&D: decontamination and decommissioning; E: bid selection; O&M: operation and maintenance; SU: commissioning.

IX–3. CALCULATION DETAILS

IX–3.1. Capital cost

The first step is the calculation of the TLCC, which has two major components — the overnight cost (COVNT) and the interest during construction (IDC). The overnight cost consists of a base cost (direct plus indirect plus owner's costs) plus a contingency (CONT) to account for items that may not be accounted for and other cost risks. The contingency generally decreases with increasing detail level of the underlying estimate.

The direct cost (CDIRECT) inputs can be entered at the subsystem level (i.e. separate cost (code of account) lines for the civil, nuclear island, electrical, heat management and other subsystems). If these subsystem costs can be linked to a separate reactor design/cost scaling model, G4-ECONS can be used in conjunction with an optimization tool to minimize the LUEC for a given reactor technology concept. It is the intent of the EMWG that this model be so used by the design teams for the six reactor systems, as well as providing a 'level playing field' means of comparing the six concepts.

Indirect costs (CINDIRECT) are also partitioned by a code of accounts system that separates home office and site located management and support categories. Owner's costs (COWNER), such as startup and training, are then added to this base cost sum (CBASE). In summary:

$$\mathrm{CBASE} = \mathrm{CDIRECT} + \mathrm{CINDIRECT} + \mathrm{COWNER}$$

$$\mathrm{COVNT} = \mathrm{CBASE} + \mathrm{CONT}$$

$$\mathrm{TLCC} = \mathrm{COVNT} + \mathrm{IDC}$$

In G4-ECONS, there is also the option of adding the reactor first core fuel load to the TLCC. In the United States of America (USA), the first core is normally carried in the fuel cycle cost; however, in a smaller nation, the first core might be included in the reactor purchase and financing structure. In order to derive the lump sum costs defined above, some sort of cost estimate must be prepared. The Generation IV Cost Estimating Guidelines [IX–1] present detailed methodologies and a standard code of accounts for reactor systems. Both the traditional 'bottom-up' cost estimating method and the more subjective 'top-down' method (based on scaling from other estimates) are described in detail.

The IDC component of the TLCC depends on the duration of the front end activities, their timing, plus the discount rate.

For model simplicity, it is assumed that spending peaks in the middle of the front end project capital campaign, and that a sine wave function (Fig. IX–2) spread over the total front end project duration provides an acceptable mathematical approximation. Cumulative expenditures can then be represented by an S-shaped curve or 'S-curve' (Fig. IX–3) for purposes of interest calculation. In order to provide more modelling accuracy and fidelity, the interest payments are assumed to be made on a quarterly basis; hence, a quarterly discount or interest rate must be calculated. Interest is accumulated from the midpoint of each quarter until the beginning of commercial electricity production. The sum of all the interest payments is the total IDC. The use of the generic S-curve was selected because it is typical for many projects, and it prevents the model user from having to derive and manually enter capital cash flow information.

IX–3.2. Amortization/capital recovery

G4-ECONS must now convert the sum of the overnight and IDC (i.e. the TLCC) into an annual cash stream that recovers the TLCC over the life of the plant. In essence, the 'construction loan + interest' must be amortized in the same manner that a home loan is amortized in the USA.

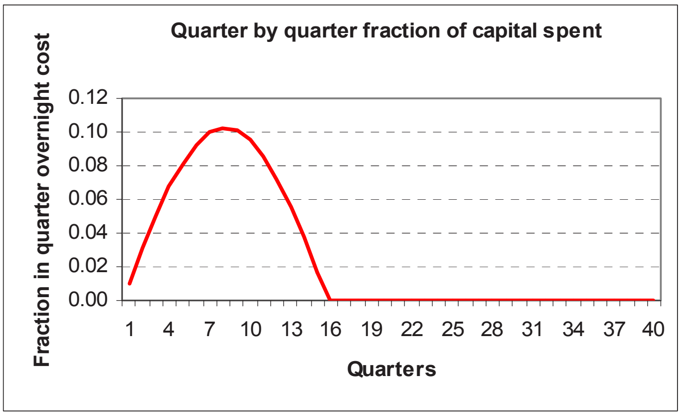


FIG. IX–2. Sine wave pattern for quarterly cash flows comprising the overnight cost.

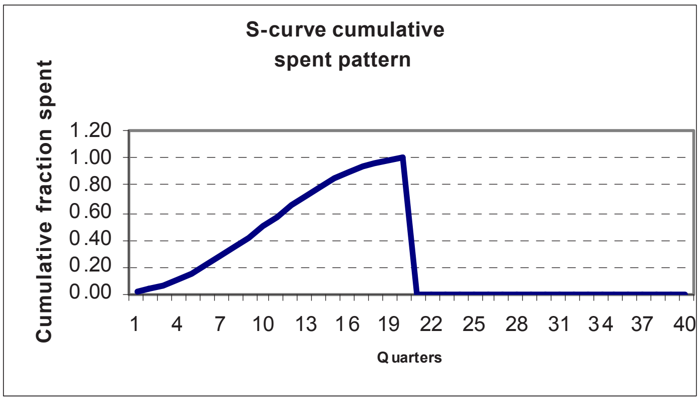


FIG. IX–3. S-curve pattern for timing of cumulative quarterly overnight cost expenditure (5 year project example).

The factor that accomplishes this calculation is called a simple fixed charge rate, and is calculated as:

$$\text{CRF} = i/[1 - (1 + i)^{-L}] \qquad \text{(IX–1)}$$

where

i is the real discount rate (annual);

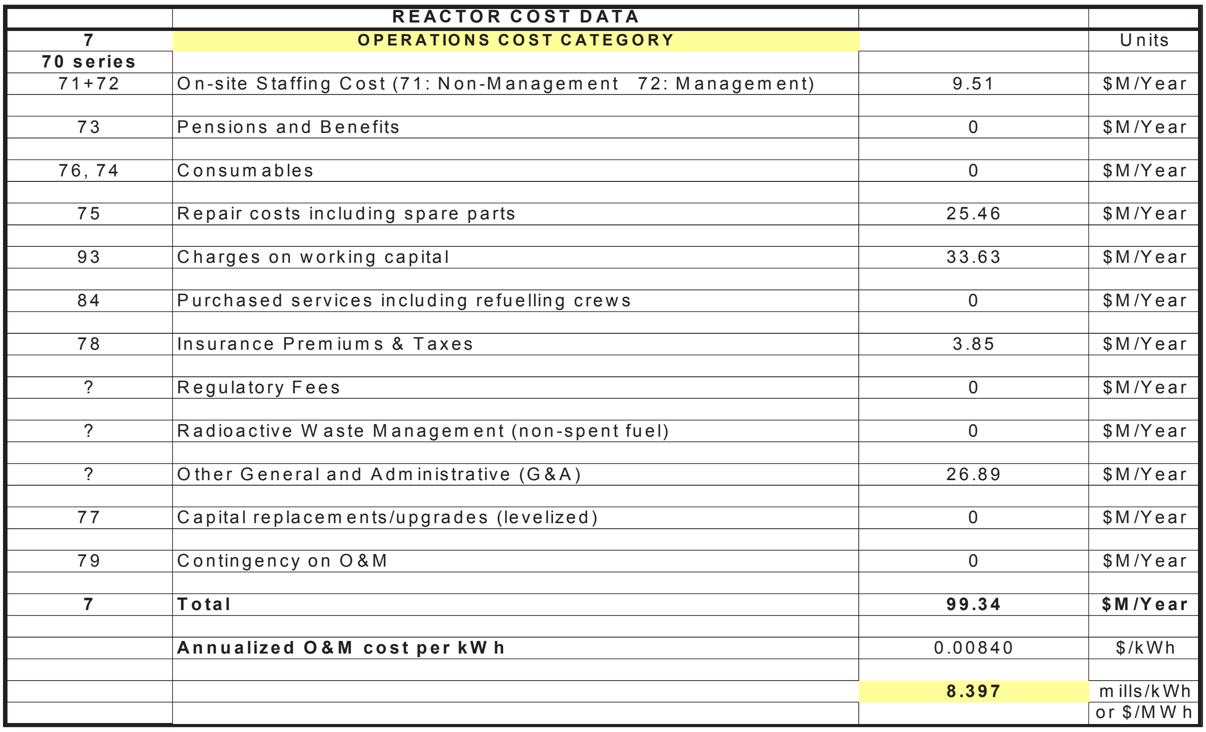
and L is the plant operating life in years.

In this model, the plant economic life is assumed to be the same as the operational life. This allows the calculation of an LUEC that is the same over the entire life of the plant and does not change after the plant is amortized, as would be the case if the plant economic life were shorter than the operating life. Actually, this latter ‘shorter write-off’ case is more realistic in practice; however, this model is designed for comparison of technologies, not financial planning for a particular project. The levelized annual capital charge, ANNCAP, typically expressed in million $/a, is calculated as follows:

$$\text{ANNCAP} = \text{CRF} \times \text{TLCC} \qquad \text{(IX–2)}$$

IX–3.3. Non-fuel O&M costs

Non-fuel O&M costs are also assigned specific cost code of accounts categories, such as staffing, regulation, maintenance and overhead, for data input. The way the numbers are rolled up into these categories is highly subjective, and often depends on corporate and national industry practice. Figure IX–4 shows some categories and a code of accounts structure used in an example G4-ECONS case for a 1300 MW(e) US pressurized water reactor (PWR) (values in dollars, 2001).



	REACTOR COST DATA		
7	**OPERATIONS COST CATEGORY**		Units
70 series			
71+72	On-site Staffing Cost (71: Non-Management 72: Management)	9.51	$M/Year
73	Pensions and Benefits	0	$M/Year
76, 74	Consumables	0	$M/Year
75	Repair costs including spare parts	25.46	$M/Year
93	Charges on working capital	33.63	$M/Year
84	Purchased services including refuelling crews	0	$M/Year
78	Insurance Premiums & Taxes	3.85	$M/Year
?	Regulatory Fees	0	$M/Year
?	Radioactive Waste Management (non-spent fuel)	0	$M/Year
?	Other General and Administrative (G&A)	26.89	$M/Year
77	Capital replacements/upgrades (levelized)	0	$M/Year
79	Contingency on O&M	0	$M/Year
7	**Total**	**99.34**	**$M/Year**
	Annualized O&M cost per kWh	0.00840	$/kWh
		8.397	mills/kWh or $/MWh

FIG. IX–4. Typical cost categories for annual non-fuel operation and maintenance (O&M) costs.

The model user simply enters the projected average annual non-fuel O&M costs for each category, and the model sums them to obtain the total annual O&M cost, ANNOM, typically also expressed in million $/a.

IX–3.4. Fuel cycle cost

The fuel cycle cost calculation is the most complex part of the G4-ECONS model. When development of G4-ECONS began, it was realized that the amount of detailed fuel cycle information the EMWG would receive from the Generation IV development teams was likely to be very small. In some cases, all that might be available would be physical and chemical definitions of the fuel material, the enrichment of the fissile material therein, its projected burnup or cycle time, and the total fuel mass for an assembly or the entire reactor core. It was soon realized that many steps in some advanced fuel cycles, particularly those that involve fuel recycle or actinide partitioning/transmutation (P/T), are not commercially available, and that for such systems, new fuel cycle facilities involving new processes would have to be designed, built and operated. There would be no information readily available on prices, process losses, timing of purchases or even optimum facility size for many steps. This was the same problem encountered in the United States Department of Energy advanced fuel cycle initiative (AFCI) programme, and is still true for the GNEP into which AFCI has evolved. It became apparent that the best option for both the Generation IV and AFCI programmes was to develop snapshot in time models based on projected fuel material balances for the reactor systems of interest. The modeller could, for example, take an ‘equilibrium’ cycle and divide it up into definable fuel cycle steps for which unit cost information was available or derivable.

Figure IX–5 shows, in modular fashion, the list of fuel cycle steps from which nearly any type of reactor fuel cycle can be constructed. Open, partially closed, totally closed and P/T fuel cycles can all be constructed from constituent modules (for the AFCI/GNEP work, each module is given a designated letter for identification). The activities in the entire fuel cycle are presented in Table IX–1.

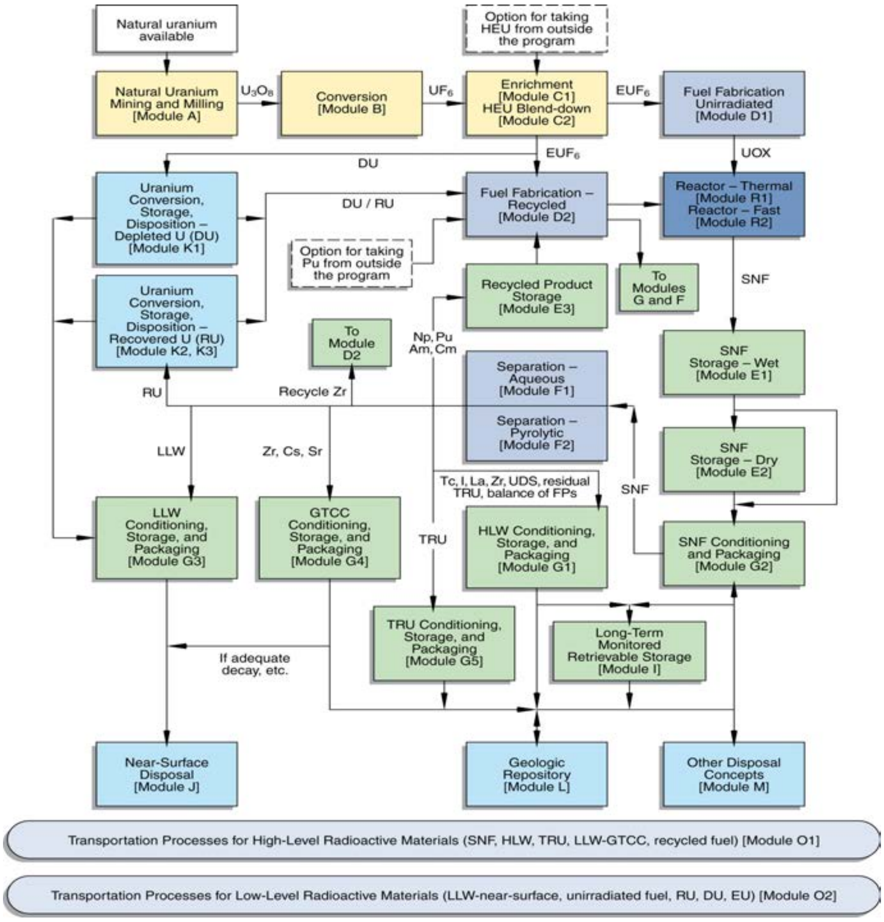


FIG. IX–5. Modular representation of fuel cycle steps. DU: depleted uranium; EU: enriched uranium; FP: fission product; GTCC: gas turbine combined cycle; HEU: highly enriched uranium; HLW: high level waste; LLW: low level waste; RU: recovered uranium; SNF: spent nuclear fuel; TRU: transuranic; UOX: uranium oxide.

Working backwards and forwards from the reactor module (R1 or R2), the necessary front end and back end fuel cycle steps are identified, and a material balance developed for each step, depending on the annual mass flow requirements from the previous (in terms of flow directionality) step. In order to keep this model simple, material losses between steps are ignored. (Since most nuclear materials have high values, these losses tend to be minimal or the materials are recycled internally within a step.) Once the annual flow (typically in kg/a) into a module or 'box' is identified, the annual flow is multiplied by the unit cost of that step to obtain an annual cost for that step. Figure IX–6 shows how all of the relevant annual costs for the required steps can be summed to a total, ANNFC, and then divided by the amount of electricity produced by the reactor to obtain an average mills/kW·h or $/MW·h fuel cycle cost.

The unit cost inputs ($/kg of material or service) that are required for the model and addressed here depend on the following factors:

- Fissile/fertile materials used (natural uranium, low enriched uranium, highly enriched uranium, mixed oxide fuel, uranium–thorium, etc.);
- Enrichment of fissile materials;
- Other materials in the fuel assemblies (zirconium, graphite, etc.);

— Services required to produce the required materials (mining, milling, conversion, enrichment, fabrication);

— Costs of spent fuel disposal or reprocessing and low and high level waste (including transuranic waste) disposal;

— Storage of critical materials.

TABLE IX–1. ACTIVITIES IN THE FUEL CYCLE

Activities	Units
Mining and milling	\$/kg U_3O_8
U_3O_8 to UF_6 conversion	\$/kg U
Uranium enrichment	\$/SWU
Fuel fabrication	\$/kg HM
Spent fuel storage	\$/kg HM
Repository disposition of spent fuel	\$/kg HM or mills/kW·h
Reprocessing	\$/kg HM
Repository disposition of high level waste	\$/kg HM equivalent

Note: HM: heavy metal; SWU: separative work unit; 1 mill = $\$10^{-3}$.

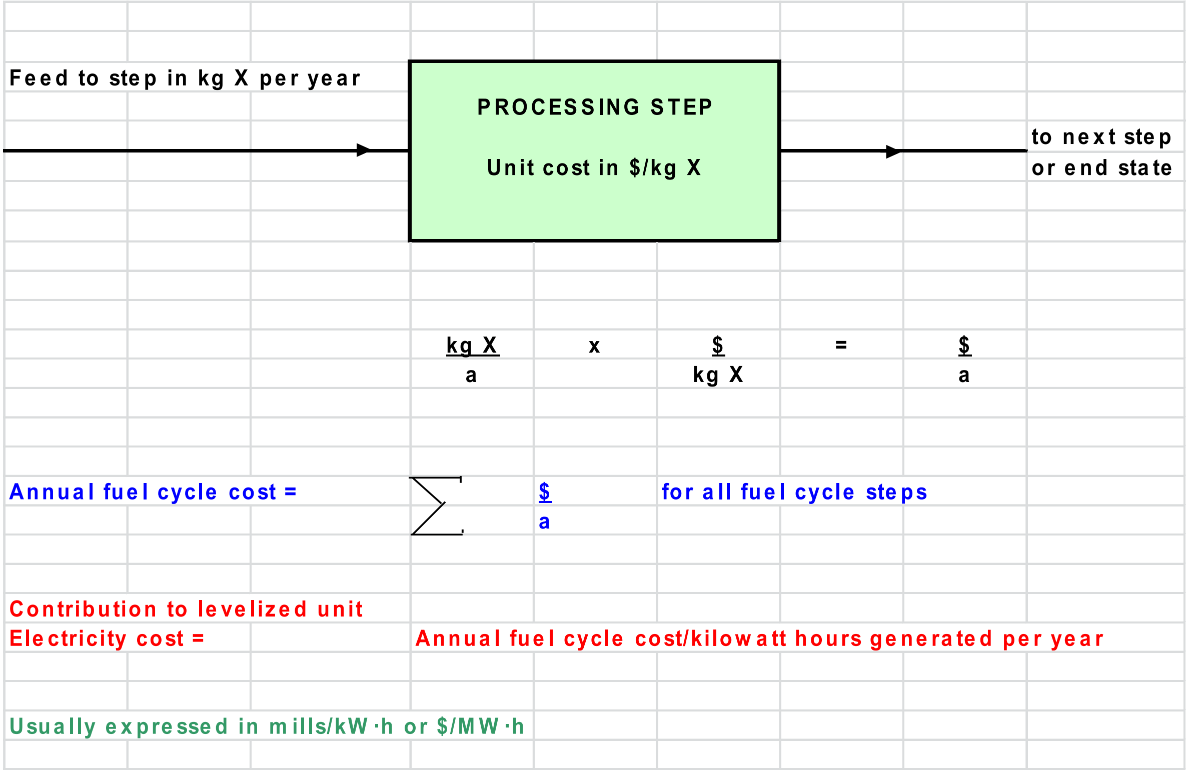


FIG. IX–6. Simplified algorithm for fuel cycle cost derivation.

The availability of existing fuel infrastructure or the requirement to create new infrastructure is a key driver of fuel cycle unit costs. For infrastructure that does not yet exist, the EMWG recommends that sufficient fuel cycle facility capacity be costed such that 32 GW of fleet capacity for the given Generation IV reactor type can be supported. At this level of production, it is likely that competitive economics based on process learning and experience will have been realized. The calculation of projected unit costs from such presently non-existent facilities is discussed below.

Before considering individual fuel cycle steps, it should be noted that the US AFCI programme has created a very large report [IX–4] and database on nuclear fuel cycle process and cost information for all of the fuel cycle steps shown in Fig. IX–6. References [IX–4, IX–5] should be very helpful to the G4-ECONS user in selecting input unit cost values for all fuel cycle steps. Typical fuel cycle related inputs to the G4-ECONS fuel cycle module include the following, and the choice of inputs depends on the nature of the fuel cycle evaluated.

IX–3.5. Fuel cycles explicitly modelled by G4-ECONS

Using the methodology outlined above, G4-ECONS has the capability to model three 'hard wired' fuel cycles. Hard wired means that the program predetermines which steps constitute the particular fuel cycle option (three options are available), and the program automatically fills out the flow charts/summary diagrams and displays the fuel cycle component of the LUEC. All three flow chart examples are shown below. The three fuel cycle options are:

(a) Fuel cycle code 1: open fuel cycle (no recycle and planned repository disposal of spent fuel). This option describes today's light water reactor (LWR) reactor systems in the USA, and can also be used for gas cooled reactors, for which fuel recycle is less likely.

(b) Fuel cycle code 2: partial recycle (meant for thermal reactors; reprocessed uranium (RepU) is reconverted, re-enriched and refabricated to produce LWR fuel assemblies). The separated plutonium is diluted with DUO_2 to produce thermal mixed oxide (MOX) fuel assemblies. The fuel assemblies produced from this single recycle mode are credited back to the fuel cycle at a unit (per assembly) value equivalent to an original virgin EUO_2 fuel assembly. There is also the option to store or dispose of the RepU instead of recycling it.

(c) Fuel cycle code 3: total recycle. This option is for fast reactor systems that operate in the high conversion ratio or breeder mode. Make-up uranium is supplied to the system to account for the fission products that are removed. There is also the option to store the excess plutonium produced.

It should be noted that the fuel cycle model in the G4-ECONS reactor model is designed to consider 'one reactor at a time'. It is not designed to model symbiotic systems, such as those proposed in the US GNEP programme, where actinide products from reprocessing of fuel from many LWRs becomes the make-up feed for a series of actinide burning fast reactors. These cases have to be modelled with stand alone spreadsheets/flow diagrams, where the user selects fuel cycle steps from different reactor systems and integrates them manually (i.e. flowsheets are not created automatically as is the case with G4-ECONS). The 2006 Advanced Fuel Cycle Economic Sensitivity Analysis report [IX–5] shows two cases (single tier thermal and fast recycle of actinides) where symbiotic fuel cycles were modelled in order to affect thermal and fast reactor destruction of actinides.

Figure IX–7 shows the fuel cycle module output from G4-ECONS for an open cycle. The example reactor is a Generation III+ ABB-CE System 80+ design, for which cost and fuel cycle material balance information was available. The unit cost values selected for input are the most likely values from the 2007 Advanced Fuel Cycle Cost Basis report [IX–4].

The reactor is assumed to undergo refuelling every 18 months, and has a fuel burnup of ~47 000 MW·d per metric tonne of heavy metal (HM). It should be noted that G4-ECONS has an internal enrichment calculator in order to calculate the separative work unit requirements to produce EUO_2 fuel of a specified ^{235}U content. The programme can also automatically find the optimal tails assay that minimizes the cost of EUF_6 to the front end of the fuel cycle. The spent fuel repository cost can be entered in terms of \$/kg HM or in mills/kW·h. For the burnup shown in Fig. IX–8, a 1 mill/kW·h waste fee would translate to just under \$400/kg HM. The ultimate long term cost of repository spent fuel disposition is still a major unknown.

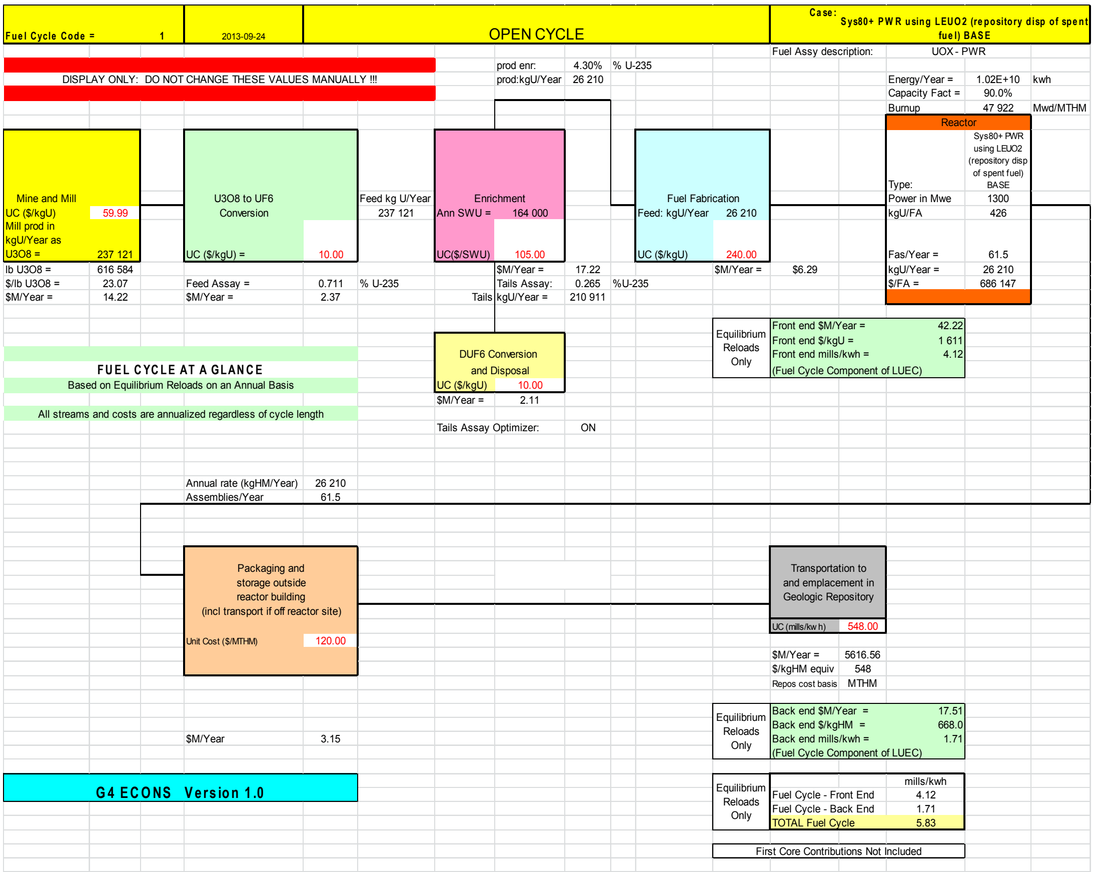


FIG. IX–7. Example flow chart produced by the G4-ECONS fuel cycle model for an open cycle.

Figure IX–8 represents ‘fuel cycle code 2’, where the LWR fuel is assumed to be reprocessed, in this case, by a PUREX (plutonium and uranium recovery by extraction) system, and the separated RepU and plutonium are utilized to produce energy equivalent fuel assemblies that can displace EUO$_2$ assemblies. In this ‘partial recycle’ mode, which assumes a one time only use of the recycled MOX/RepU assemblies, approximately 20% of the original EUO$_2$ number of fuel assemblies reloaded are returned for credit as recycle assemblies (this cycle is sometimes called MONOMOX, since the MOX is assumed to undergo only one recycle). In the case shown, the front end of the fuel cycle is nearly identical to the open cycle in Fig. IX–7. This partial recycle option also has a switch that can be activated to store or dispose of the RepU instead of recycling it. There are also costs associated with these paths. Again, the input unit costs are taken from the 2007 Advanced Fuel Cycle Cost Basis report [IX–4].

Figure IX–9 shows a schematic for a nearly totally closed fuel cycle (i.e. fuel cycle code 3). The reactor and fuel cycle information were supplied to Generation IV EMWG by its Japanese participants. The reactor is a large sodium cooled fast reactor utilizing (Pu, U)O$_2$ MOX fuel. The reactor is called the Japanese sodium cooled fast reactor (JSFR), and represents the major development item in the Japanese Generation IV programme. This reactor is a heterogeneous system; hence, drivers and blankets are utilized. In the G4-ECONS representation, however, the uranium in the blankets is combined with the plutonium and uranium in the driver fuel for purposes of analysis. Aqueous reprocessing of fast reactor drivers and blankets is assumed. Depleted uranium is supplied to the fuel fabrication facility as make-up to the overall recycle system. The unit costs used in Fig. IX–9 were provided by Japanese members of the EMWG. It should be possible to run similar cases for other fast reactor systems such as the PRISM system being proposed by General Electric in the USA.

Future efforts in G4-ECONS fuel cycle modelling will be oriented towards creating a fuel cycle specifically oriented to actinide burning, where lower fast reactor conversion ratios will be required. It will also be necessary to modify the closed cycle model such that drivers, blankets and targets can be accounted for separately. The European ‘red impact’ programme is also considering actinide burning and P/T cycles and using a methodology similar to that described here. The International Congress on Advances in Nuclear Power Plants 2007 paper describing this effort is listed as Ref. [IX–6].

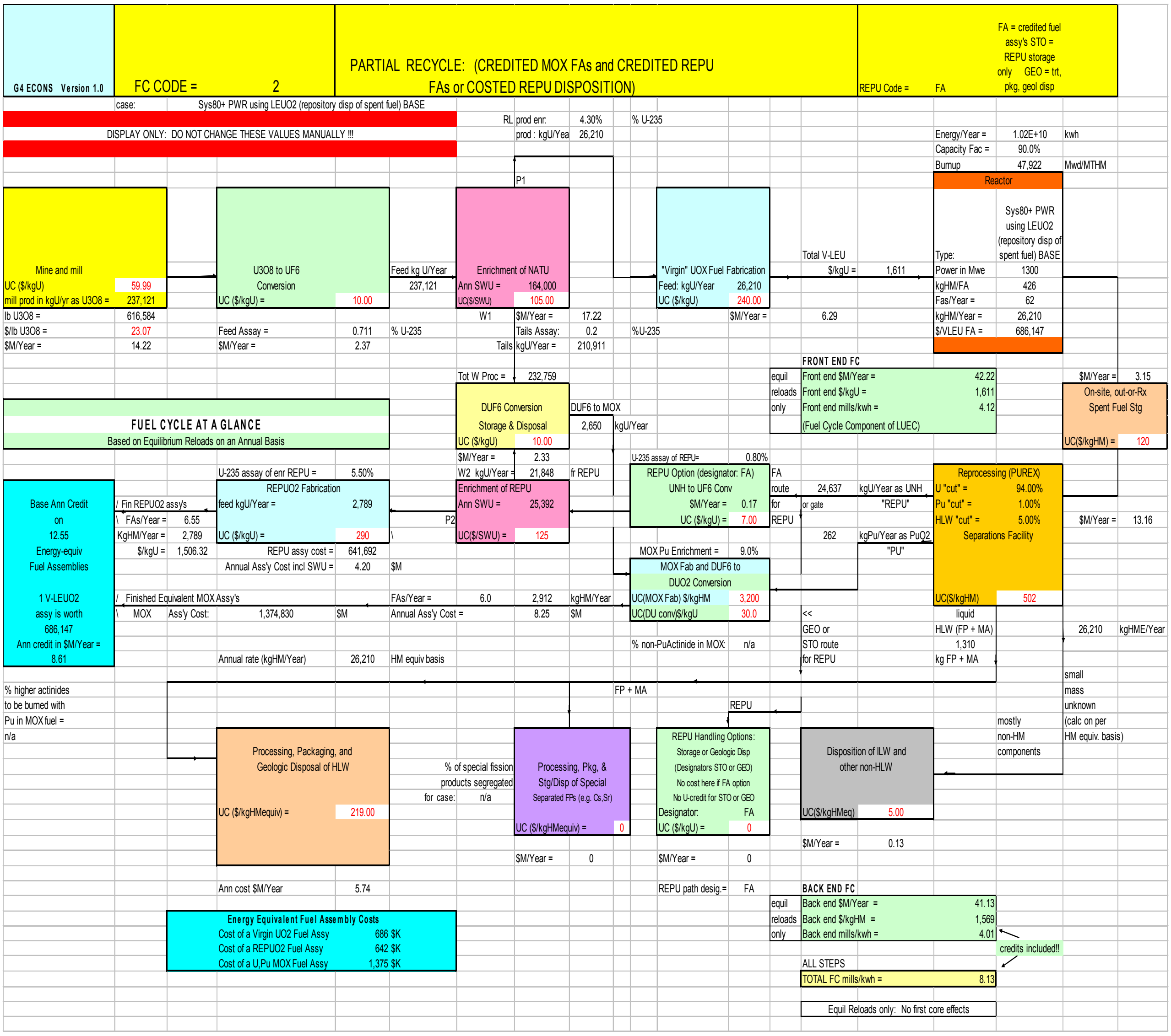


FIG. IX–8. Example flow chart produced by the G4-ECONS fuel cycle model for a partially closed fuel cycle.

IX–3.6. Reactor D&D cost

The D&D cost is annualized by use of a sinking fund calculation, with the calculated annual payment based on the projected D&D funding requirement at end of life and the discount rate. The sinking fund factor (SFF) is calculated as follows:

$$\mathrm{SFF} = i/\{[(1 + i)^L] - 1\} \qquad \text{(IX–3)}$$

where

i is the real discount rate;

and L is the plant operating life.

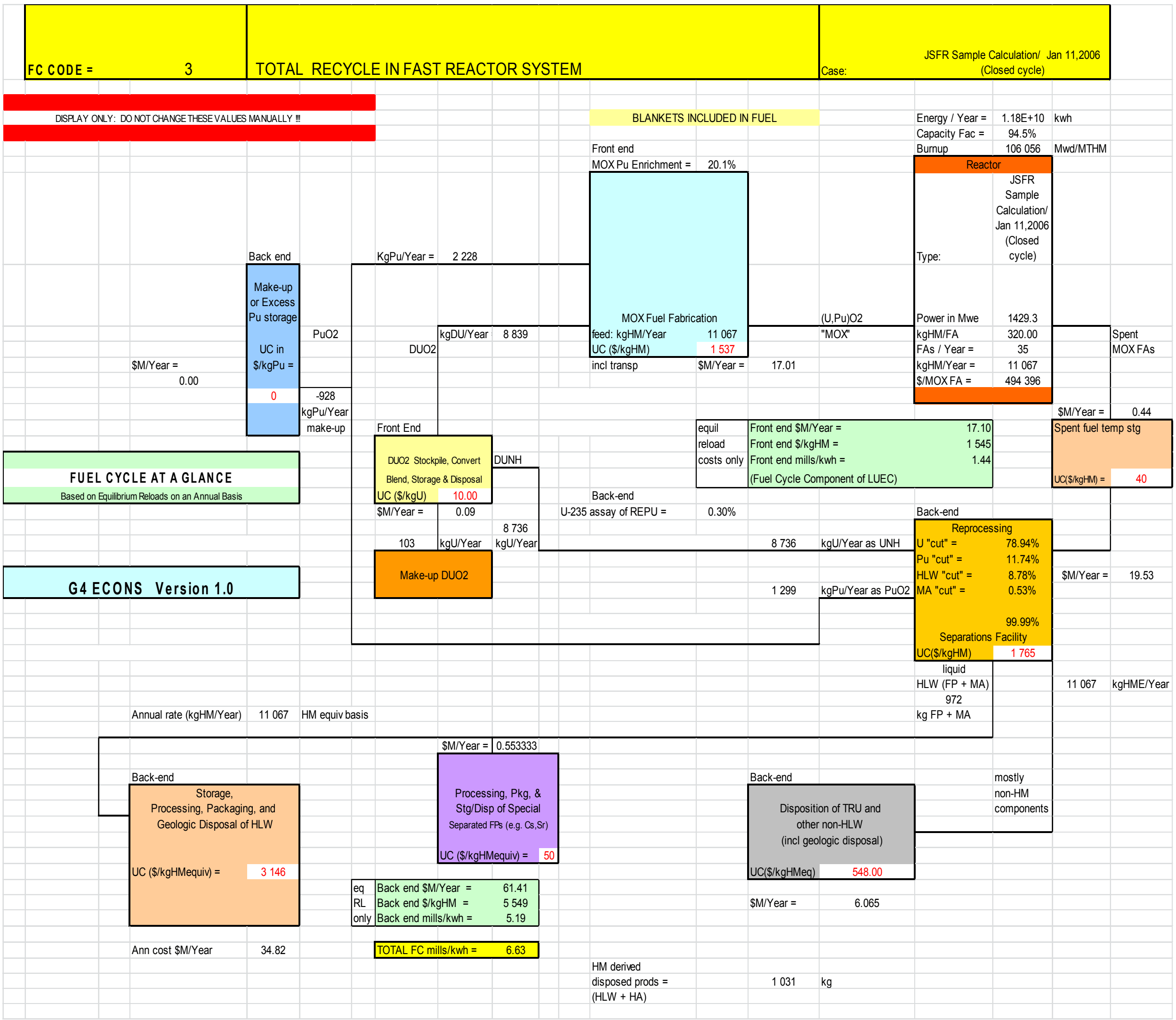


FIG. IX–9. Example flow chart produced by the G4-ECONS fuel cycle model for a totally closed fuel cycle.

The annual amount that must be set aside every year is:

$$\text{ANNDD} = \text{SFF} \times \text{CDD} \qquad \text{(IX–4)}$$

where

ANNDD is the annual payment into the sinking fund, typically in million $/a;

and CDD is the constant dollar lump sum estimate of what is required at the end of plant life for D&D of the plant to whatever regulatory requirements allow.

IX–3.7. Components of the LUEC

The model has now calculated four annual costs that, in constant dollars, are the same each year over the life of the plant. These are:

- ANNCAP: the annual capital recovery cost;
- ANNOM: the annual non-fuel O&M cost;
- ANNFC: the annual fuel cycle cost;
- ANNDD: the annual payments to the D&D sinking fund.

In order to convert these to components of the LUEC, typically in mill/kW·h or $/MW·h, one merely divides each of the components above by the annual power production. The electrical power production in kW·h/a is calculated as follows:

$$\text{ANNENERGY} = \text{NETCAP} \times 1000 \times 8766 \times \text{CAPFAC} \qquad \text{(IX–5)}$$

where

NETCAP	is the nuclear power plant's net power capacity in MW(e);
CAPFAC	is the average projected plant capacity factor over the entire plant life;
8766	is the average number of hours in a year (including the effect of leap years);

and 1000 is the number of kilowatts in 1 MW.

The four LUEC components are therefore:

Capital: LCAP = ANNCAP/ANNENERGY

Non-fuel: LOM = ANNOM/ANNENERGY O&M

Fuel cycle: LFC = ANNFC/ANNENERGY

D&D: LDD = ANNDD/ANNENERGY (IX–6)

The total LUEC is:

$$\text{LUEC} = \text{LCAP} + \text{LOM} + \text{LFC} + \text{LDD} \qquad \text{(IX–7)}$$

Table IX–2 shows the LUEC components from an actual G4-ECONS-R run for a PWR. The fuel cycle cost for this case has been partitioned into both its front end (ore, conversion, enrichment and fuel fabrication) and back end (spent fuel storage and repository disposition) components.

IX–4. MODEL TESTING AND VALIDATION

The G4-ECONS model has been tested on the following systems for which cost input data were available: System 80+ PWR, a Massachusetts Institute of Technology design for a pebble bed modular reactor, and the JSFR. It can also be used to evaluate small and medium reactor concepts.

The System 80+ case and the JSFR case were run with other more complex generation cost models, and good agreement of the output results was found when the same input values were submitted to each model.

TABLE IX–2. G4-ECONS OUTPUT TABLE FOR A TYPICAL PWR (YEAR 2001 FUEL CYCLE PRICES)

Summary of model results		
Discount rate = 10%		
	Annualized cost ($M/a)	mills/kW·h or $/MW·h
Capital (including first core and financing)	327.19	35.91
Operations cost	78.47	8.61
Fuel cycle — front end	29.07	3.19
Fuel cycle — back end	9.90	1.09
D&D sinking fund	0.68	0.07
Total LUEC	445.31	48.88

Note: Constant dollars, 2001. D&D: decontamination and decommissioning; LUEC: levelized unit electricity cost; PWR: pressurized water reactor; 1 mill = $\$10^{-3}$.

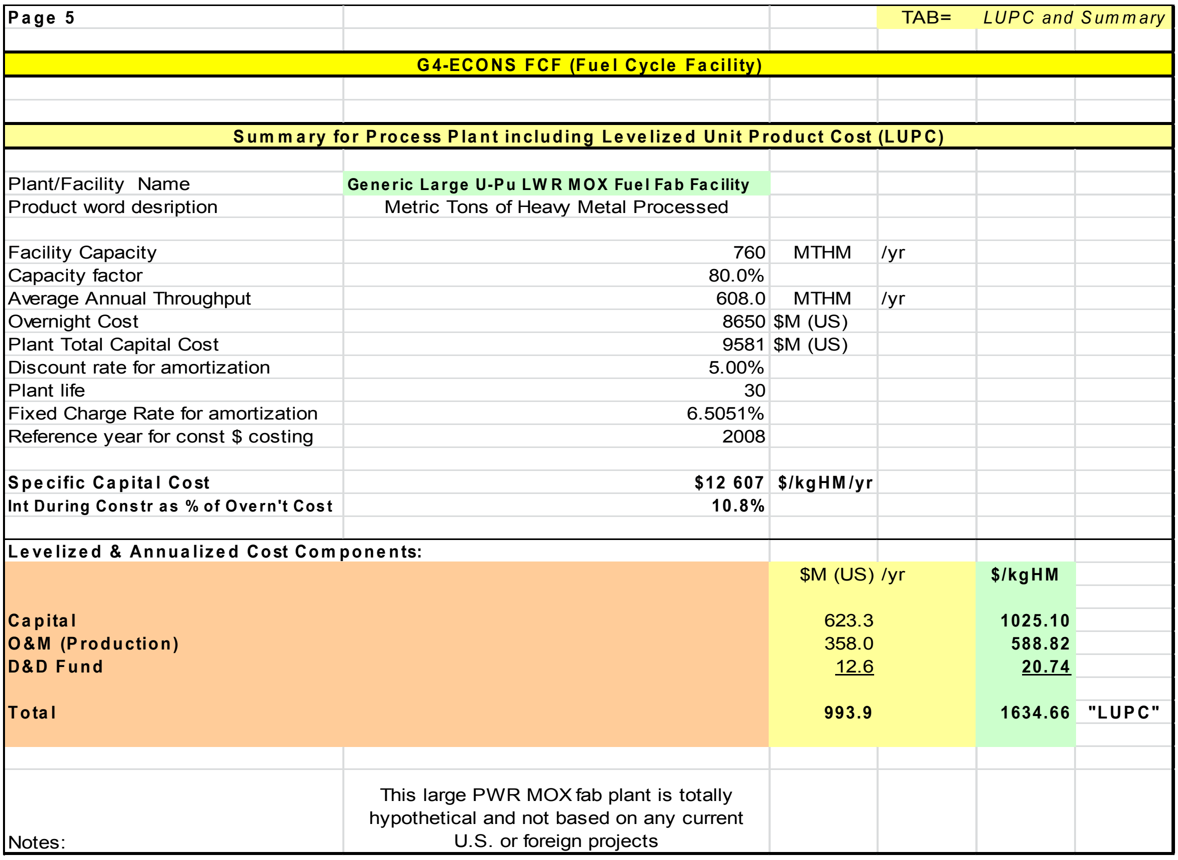
IX–5. COSTING OF FUEL CYCLE SERVICES AND MATERIALS NOT AVAILABLE COMMERCIALLY — THE G4-ECONS FUEL CYCLE FACILITY MODEL

For some Generation IV concepts, fuel cycle cost information will be required for fuel types or fuel services that are not now commercially available. These services may have little cost or price information available. Estimating teams should still be able to calculate the levelized unit costs for these fuels ($/kg HM) or services ($/unit of fabrication, reprocessing, etc.) initially with a top-down cost estimating approach plus the appropriate levelization algorithms. The estimate should start with information from the Generation IV fuel cycle system designers and sources within the United States Department of Energy AFCI programme such as the 2007 Advanced Fuel Cycle Cost Basis report [IX–4]. A unit cost can be built from the following data:

- Fuel cycle facility base and owner’s costs (for the capital component of the fuel cycle cost);
- Design/construction duration (for IDC calculation);
- Contingency (part of the overnight cost);
- Annual production from the plant, for example, kg HM/a (assumed constant over the life of the plant);
- Number of years of commercial operation (for recovery of capital);
- Annual operating costs (million $/a);
- Interim replacement rate for capital equipment (treated as an annual average cost like O&M and included in the O&M annual cost summation);
- Cost of plant D&D (recoverable by use of a sinking fund);
- Number of years the D&D fund is to be collected.

The cost summation and levelization algorithms required for this calculation are basically the same as for the reactor described above, except that no fuel cycle component is calculated; only capital recovery, O&M and D&D are calculated. A special generic version of G4-ECONS, called the G4-ECONS fuel cycle facility (FCF), will be available specifically to address the economics of new fuel cycle process facilities. Most facility concepts will need to start with top-down estimating based on alteration of reference processes to accommodate new fuel cycles. The most likely fuel cycles to require this type of analysis are fuel fabrication facilities for advanced reactor types, fuel reprocessing facilities and special separation facilities, such as for actinides. As mentioned earlier, the estimator should assume that sufficient fuel cycle capacity is designed and estimated to service 32 GW of reactor capacity.

Figure IX–10 shows the actual output from a run of G4-ECONS FCF for a hypothetical LWR MOX fuel fabrication facility.



Page 5			TAB=	LUPC and Summary	
G4-ECONS FCF (Fuel Cycle Facility)					
Summary for Process Plant including Levelized Unit Product Cost (LUPC)					
Plant/Facility Name	**Generic Large U-Pu LWR MOX Fuel Fab Facility**				
Product word desription	Metric Tons of Heavy Metal Processed				
Facility Capacity	760	MTHM	/yr		
Capacity factor	80.0%				
Average Annual Throughput	608.0	MTHM	/yr		
Overnight Cost	8650	$M (US)			
Plant Total Capital Cost	9581	$M (US)			
Discount rate for amortization	5.00%				
Plant life	30				
Fixed Charge Rate for amortization	6.5051%				
Reference year for const $ costing	2008				
Specific Capital Cost	**$12 607**	**$/kgHM/yr**			
Int During Constr as % of Overn't Cost	**10.8%**				
Levelized & Annualized Cost Components:					
		$M (US) /yr		**$/kgHM**	
Capital		623.3		**1025.10**	
O&M (Production)		358.0		**588.82**	
D&D Fund		12.6		**20.74**	
Total		**993.9**		**1634.66**	**"LUPC"**
Notes:	This large PWR MOX fab plant is totally hypothetical and not based on any current U.S. or foreign projects				

FIG. IX–10. *Output table from G4-ECONS fuel cycle facility showing the break-down of the unit cost.*

IX–6. PLANS FOR VERSION 2.0 OF THE G4-ECONS REACTOR MODEL

Development of version 2.0 of G4-ECONS is now essentially complete and is undergoing testing. This revised model will allow for the calculation of the levelized unit cost of energy products other than electricity from the reactor or co-production of other products and electricity. Among such products are hydrogen, process heat, desalinated water and, ultimately, actinide destruction services. Figure IX–11 shows some of these products.

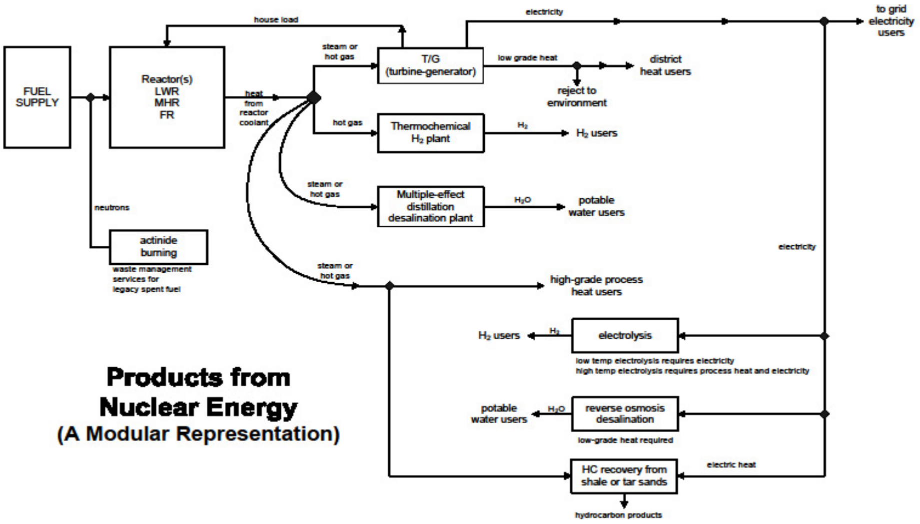


FIG. IX–11. *Nuclear energy products. FR: fast reactor; HC: hydrocarbon; LWR: light water reactor; MHR: modular helium reactor.*

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Annex X

HYDROGEN OR FOSSIL COMBUSTION NUCLEAR COMBINED CYCLE SYSTEMS FOR BASELOAD AND PEAK LOAD ELECTRICITY PRODUCTION

Oak Ridge National Laboratory, United States of America

X–1. SUMMARY

A combined cycle power plant is described that uses: (i) heat from a high temperature nuclear reactor to meet baseload electrical demands; and (ii) heat from the same high temperature reactor and burning natural gas, jet fuel or hydrogen to meet peak load electrical demands. For baseload electricity production, fresh air is compressed, then flows through a heat exchanger, where it is heated to between 700 and 900°C by using heat provided by a high temperature nuclear reactor via an intermediate heat transport loop, and finally exits through a high temperature gas turbine to produce electricity. The hot exhaust from the Brayton cycle gas turbine is then fed to a heat recovery steam generator that provides steam to a steam turbine for added electrical power production.

To meet peak electricity demand, the air is first compressed and then heated with the heat from a high temperature reactor. Natural gas, jet fuel or hydrogen is then injected into the hot air in a combustion chamber, combusts and heats the air to 1300°C — the operating conditions for a standard natural gas fired combined cycle plant. The hot gas then flows through a gas turbine and a heat recovery steam generator before being sent to the exhaust stack. The higher temperatures increase the plant efficiency and power output. If hydrogen is used, it can be produced at night using energy from the nuclear reactor and stored until required. With hydrogen serving as the auxiliary fuel for peak power production, the electricity output to the electrical grid can vary from zero (i.e. when hydrogen is being produced) to the maximum peak power while the nuclear reactor operates at constant load. As nuclear heat raises air temperatures above the auto-ignition temperatures of the various fuels and powers the air compressor, the power output can be varied rapidly (compared with the capabilities of fossil fired turbines) to meet spinning reserve requirements and stabilize the electrical grid.

This combined cycle uses the unique characteristics of high temperature reactors ($T > 700°C$) to produce electricity for premium electricity markets whose demands cannot be met by other types of nuclear reactor. It may also make the use of nuclear reactors economically feasible in smaller electrical grids, such as those found in many developing countries. The ability to rapidly vary power output can be used to stabilize electrical grid performance — a particularly important requirement in small electrical grids.

X–2. INTRODUCTION

A new type of nuclear combustion combined cycle (NCCC) power plant is proposed that uses high temperature nuclear heat for baseload electricity production and high temperature nuclear heat supplemented with the combustion of fossil fuels or hydrogen for peak load electricity production. It is a unique application for nuclear energy in that it (i) may enable nuclear energy to meet premium price electricity market requirements in advanced industrialized countries; and (ii) may match the technical and economic requirements for a power plant connected to a small electrical grid such as those found in many developing countries. The concept, which has been under investigation for the past couple of years, is only in the early stages of development.

This report provides a system description, an initial power cycle analysis, an analysis of markets, and high temperature reactor options for an NCCC plant, as well as identification of the technical challenges. Also discussed is the option of using hydrogen as a fuel. The hydrogen used would be produced by the reactor during times of low power demand.

X–3. SYSTEM DESCRIPTION

An NCCC power plant is proposed (Fig. X–1) that uses heat from a high temperature nuclear reactor and fuel (natural gas, jet fuel or hydrogen) in order to meet the baseload and peak electrical demands.

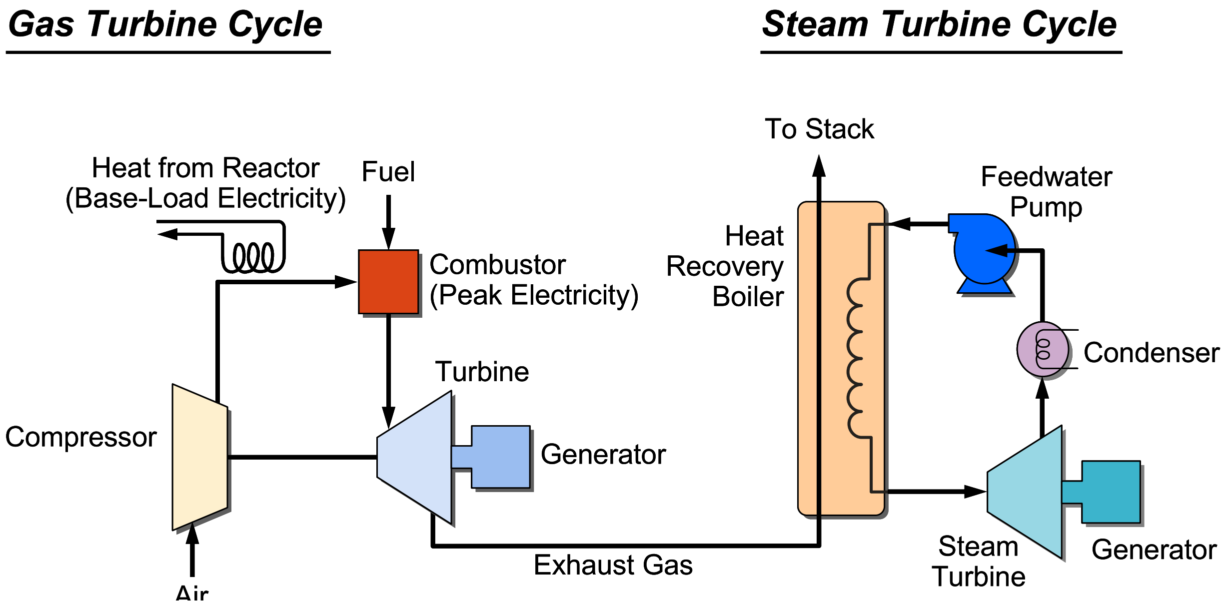

FIG. X–1. Nuclear combustion combined cycle electrical plant.

The design for this type of plant is based on preliminary work conducted on a nuclear–natural gas combined cycle system [X–1] and studies of other systems used to meet peak power demand [X–2]. For baseload electricity production, air is first compressed, then flows through a heat exchanger, where it is heated to between 700 and 900°C, and finally exits through a high temperature gas turbine to produce electricity. The heat, via an intermediate heat transport loop [X–3], is provided by a high temperature reactor [X–4, X–5]. The hot exhaust gases from the Brayton cycle turbine are then fed to a heat recovery steam generator (HRSG) that provides steam to a steam turbine for added electrical power production.

To meet peak electrical demand, after the nuclear heating of the compressed air, fuel (natural gas, jet fuel or hydrogen) is injected into the hot air and burned to increase power levels. This process raises the peak inlet temperatures to both the gas turbine and the steam turbine. In this mode of operation, the peak gas turbine inlet temperature is ~1300°C — about the same temperature and operating conditions as those of a standard utility natural gas fired combined cycle gas turbine that exhausts its heat to a bottoming Rankine steam cycle.

The nuclear heat raises the temperature of the incoming air above the auto-ignition temperature of the fuel — the temperature at which the fuel will spontaneously burn; thus, the fuel to air ratio does not need to be controlled to ensure flame stability and plant operation. The auto-ignition temperatures of natural gas, jet fuel and hydrogen are 630, 240–260 and 570°C, respectively. Consequently, the combined cycle plant can operate at any power level between baseload nuclear and the maximum peak power output. In actual practice, however, the temperatures must be somewhat above these temperatures to ensure rapid combustion.

The response time to changes in power demand is much faster in an NCCC plant than in a plant that uses traditional fossil fuelled combustion turbines. As will be discussed in Section X–6, this capability may enable this technology to meet such utility markets as (i) power regulation and (ii) small electrical grids that exist in many developing countries. This capability for rapid changes in power production is a result of the difference in operation of a conventional combustion turbine and an NCCC plant.

X–3.1. Traditional Brayton power cycle

In a traditional combustion turbine, the fuel to air ratio must be controlled to ensure flame stability. To increase the power demand, the airflow (turbine speed) and fuel injection rate are increased simultaneously. As more fuel is added, the extra power is first used to speed up the compressor and increase the airflow. Consequently, there is a significant lag time between the signal for more power and the delivery of more power. This is why the acceleration of a jet aircraft on take-off is initially slow — the initial increase in turbine power goes into increasing the compressor speed. The same is true of a utility combined cycle plant.

X–3.2. Nuclear heat Brayton power cycle

With nuclear baseload heat, the compressor operates at a constant speed with a constant airflow through the system. When additional electricity is required, fuel is injected into the system. The time between fuel injection into the burner and an increase in power level is determined by the flight time between the fuel injectors and the turbine — a fraction of a second. The air compressor does not change speed or require more energy.

The NCCC plant can use hydrogen as a fuel, an option that would enable this technology to meet variable power demands in a greenhouse constrained world in which the release of carbon dioxide to the atmosphere is limited. The hydrogen can be made by electrolysis or other methods using nuclear energy from the plant during times of low electrical demand, stored and then burned at times of peak power demand. With such a system, the nuclear reactor operates at full power at all times (except for maintenance and refuelling outages), but the electricity to the electrical grid varies from zero (electricity to hydrogen production) to full power.

The general concept of combining a nuclear and a combustion heat source is not new. The Indian Point I pressurized water reactor in New York had a high temperature steam cycle, in which the reactor provided saturated steam that was then superheated with an oil fired super heater. The technology of combining nuclear heat sources with Brayton power systems is also not new. The billion dollar Aircraft Nuclear Propulsion programme [X–6] of the 1950s, which had as its goal the development of a nuclear powered aircraft, developed designs and conducted non-nuclear tests that integrated heat from a secondary liquid heat transport loop into an aircraft jet engine. This programme was cancelled because of the weight of the aircraft reactor shielding and the risk of an aircraft crash — factors that do not apply to a stationary power station.

Initial studies with a simple nuclear natural gas cycle (Fig. X–1) indicate that the turbine conditions will be similar to those of the existing General Electric (GE) model MS7001FA gas turbine in terms of gas pressure ratios and peak temperatures. The operating points for baseload electricity production are near the peak efficiency operating conditions for the gas turbine at the lower inlet temperatures, whereas the operating points for peak power production are near the maximum power output condition for the gas turbine at the higher inlet temperatures. A simple combined cycle system was modelled using a single gas turbine with the same pressure ratio and gas flow rates as the GE turbine and a steam cycle representative of the commercial GE combined cycle machine. The calculations showed a baseload power output (both gas and steam turbine) of 68.5 MW(e) and a peak load power output of 276.5 MW(e). For baseload and peak load operations, the reactor provides a constant 175 MW(th) at 800°C. For peak power production, the natural gas provides an additional 323 MW(th) at a peak gas turbine inlet temperature of 1300°C.

The power system size is determined by the available sizes of commercial combined cycle turbines. The high temperature reactor may have multiple combined cycle systems to match reactor output to power conversion system size. The concept of multiple power conversion systems connected to a single reactor is not new. Many Russian Federation reactors have multiple steam systems connected to a single reactor because the reactor sizes were larger than the available steam turbines.

A wide variety of system configurations exist to boost baseload levels to peak power levels, improve efficiency or increase the nuclear heat fraction when the plant is operating in a peak power production mode. These configurations have not yet been analysed. As the baseload plant will operate at a high capacity factor with low cost nuclear heat, its optimum cycle may be somewhat different from that of traditional natural gas fired Brayton power cycles.

X–4. NUCLEAR HYDROGEN COMBINED CYCLE

As discussed earlier, the NCCC plant can produce hydrogen using nuclear energy during periods of low electrical demand and then use that hydrogen for peak power production. This option may become particularly attractive if there are constraints on the release of greenhouse gases to the atmosphere from burning fossil fuels. Today's options for producing hydrogen are: (i) electrolysis, which produces hydrogen from water; and (ii) steam reforming of natural gas or another fossil fuel to produce hydrogen. Use of a fossil fuel as a long term option for hydrogen production may require carbon dioxide sequestration [X–7]. Work is under way to develop lower cost methods of nuclear hydrogen production including: (i) high temperature electrolysis and hybrid cycles, which convert heat, electricity and water into hydrogen and oxygen; and (ii) thermochemical cycles, which convert heat and water into hydrogen and oxygen.

The current technology for nuclear hydrogen production is electrolysis, where large scale electrolysers have efficiencies of ~73%. This technology is advancing rapidly because potential future markets have led to major increases in research and development programmes aimed at driving down capital costs. Recent estimates by manufacturers [X–8] indicate that capital costs of ~$300/kW are achievable within the next few years — partly as a result of improved technology and partly because of lower manufacturing costs due to higher production rates. Capital costs are measured ($/kW) in terms of the energy value of the hydrogen that is produced. The United States Department of Energy [X–9] has estimated 2006 electrolyser capital costs of $665/kW, with a goal of reducing the capital cost for distributed electrolysers at hydrogen service stations to $125/kW by 2017. If these cost goals are met, electrolyser costs will not represent a significant component of the total cost of hydrogen. Most of the cost for hydrogen production will be attributed to electricity.

If electrolysis is used to produce hydrogen, efficiency and capital costs become the critical issues. The potential efficiency gains are reasonably well known because electrolyser technology is moderately well understood, as are its sources of inefficiencies. Recent studies [X–10] of large scale electrolysis using existing technology and $0.04/kW·h electricity estimated hydrogen costs at $2.56/kg, with a cost break-down as follows: $2.08/kg for electricity, $0.28/kg for capital recovery and $0.20/kg for operations.

The use of electrolysis introduces two additional economic factors that are not associated with other methods of hydrogen production. First, the output of an electrolyser can be doubled [X–8], with some reduction of efficiency. In effect, the electrolyser capital costs per unit of output are then reduced by up to a factor of two. If very low cost electricity is available at particular times, strong economic incentives will exist to drive the electrolysers to produce more hydrogen, despite the inefficiencies, and buy the hydrogen at a lower cost. Secondly, the power to an electrolyser can be reduced or increased instantaneously or sequentially with multiple parallel electrolysers. Hence, the utility can use the electrolysers for regulation and spinning reserve (see Section X–6) by dropping or adding electrical load. This capability represents a significant economic benefit [X–11], but requires a sophisticated economic analysis to quantify the benefits.

Only one technology presently exists for low cost storage of hydrogen — storage underground in caverns or geological reservoirs. In the United States of America (USA), natural gas is stored in about four hundred large facilities, with a total capacity to store one third of a year's production of natural gas. Use of these facilities represents a low cost technology, with market prices for storage typically being 10% of the value of the natural gas.

Commercial hydrogen storage facilities using geological storage have been built in the USA and Europe. For hydrogen, the capital costs for storage are estimated to be $0.80–1.60/kg, which is lower than the total production costs for hydrogen. Although hydrogen storage technology has been used commercially in several geologies, it has not yet been demonstrated in all geologies that have been used to store natural gas.

Storage economics imply relatively large facilities. Two factors that are almost independent of facility capacity drive the facility size: siting and site development costs (including an understanding of the local geology) and gas storage, which requires compression of the gases, typically to pressures of ~7 MPa. Gas equipment efficiencies and costs are strongly dependent on the size of the equipment. Low hydrogen storage costs enable the production of hydrogen during times of the day, week or year with low electricity demand, and low electric costs for use for peak electricity at times of high electricity costs. There is the option of seasonal storage of hydrogen for electrical grids where the electrical demand and cost varies significantly, depending upon the season.

X–5. POWER CYCLE ANALYSIS

An analysis of a simplified NCCC power cycle was conducted using the power cycle described earlier, as shown in Fig. X–1. For the scoping feasibility study presented here, simplified models of the individual components of the gas turbine, HRSGs and Rankine cycles, were developed separately and then combined sequentially to determine the combined performance of the thermal power conversion system. Only steady state conditions were considered, thus energy storage or mass storage dynamic effects were not included.

X–5.1. Gas turbine cycle modelling

In order to calculate the state points of the combined thermal conversion power cycle, the gas turbine portion was developed first. In the first step of the combined cycle model, heat was added only at the compressor outlet for the simple Brayton cycle. The heat was provided by an intermediate heat transport loop from the reactor to the NCCC plant with a liquid salt as the heat transfer fluid. To start with the system model, the design parameters of a conventional utility combined cycle plant were chosen to utilize realistic existing hardware.

The algorithms used for gas turbine performance were those given by Wilson and Korakianitis [X–12]. The parameters of most significance in calculating the cycle state points were the compressor pressure ratio, the gas turbine inlet temperature, the compressor inlet temperature, the compressor and turbine polytropic efficiencies, and the total fractional pressure loss. Before determining the performance of the proposed NCCC gas turbine, the performance calculations for a simple gas turbine cycle for various parameter variations were verified against those presented by Wilson and Korakianitis [X–12].

To calculate an initial estimate of gas turbine performance, the following parameters were chosen. The high temperature heat was assumed to be provided by an advanced high temperature reactor (AHTR), with the heat delivered via a liquid salt intermediate heat transport loop (Section X–7). The ambient pressure was set to 100 kPa, as appropriate for an open cycle air machine. The turbomachine polytropic efficiencies were typical of those for the class of machines (large, axial flow) under consideration. The efficiencies, which are functions of the physical size and mass flow rate, can be updated as appropriate in the future. The major technical parameters of the AHTR are:

- Compressor inlet temperature = 10°C;
- AHTR salt temperature = 800°C;
- Combustor outlet temperature = 1300°C;
- Turbine polytropic efficiency = 0.90;
- Compressor polytropic efficiency = 0.85;
- Total fractional pressure drop ($\Delta P/P$) = 0.08.

As the reactor heat is transferred by a heat exchanger to the compressed air leaving the compressor, an additional parameter of the effectiveness of the salt to air heat exchanger was introduced and set to 0.95. The computed results, as shown in Figs X–2 to X–4, depend (some significantly, some not) on the values used for these cycle parameters. The compressor pressure ratio r_p, defined here as the outlet pressure over the inlet pressure, is a major design parameter for specifying the turbomachinery. Owing to the importance of this parameter, a number of important results were calculated as a function of compressor pressure ratio.

A significant parameter is the thermal efficiency, simply calculated here as the net shaft power ($W_{turbine} - W_{compressor}$) divided by the total heat transferred from the AHTR heat exchanger and combustor. Another important parameter is the specific power, defined as the net shaft power divided by the product of the working fluid heat capacity rate and the compressor inlet temperature (mC_pT_{inlet}). Figure X–2 shows the thermal efficiency as a function of the specific power for the given cycle parameters for various compressor pressure ratios. The calculations were initiated at a pressure ratio of 2, and the plotted points are in increments of two up to a pressure ratio of 30.

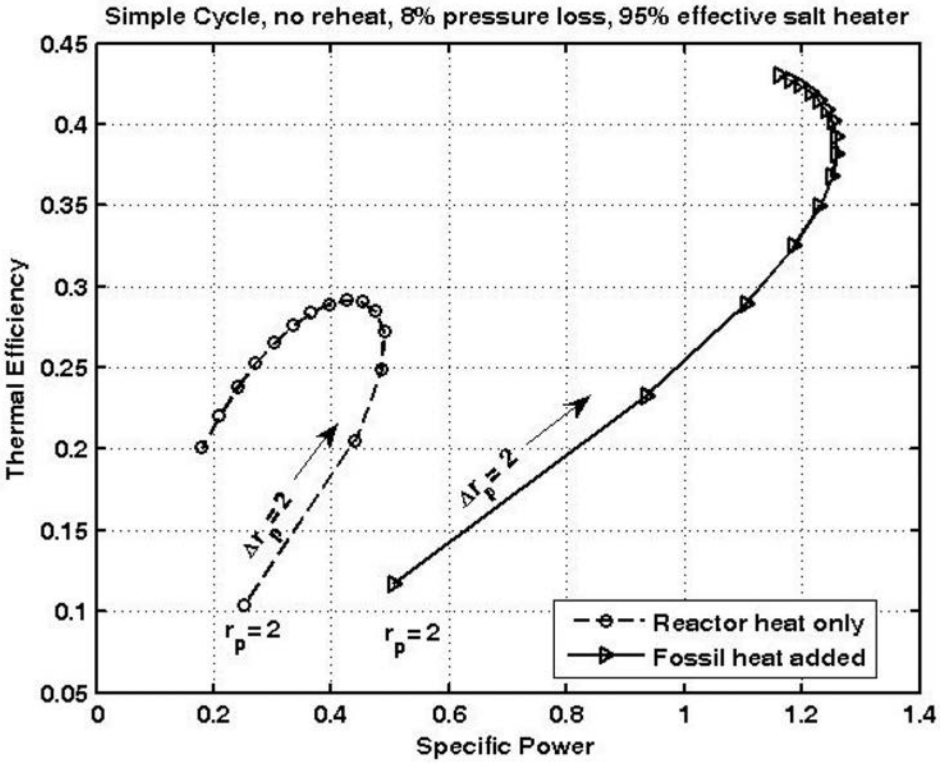

FIG. X–2. Gas turbine thermal efficiency versus specific power for pressure ratios from 2 to 30 (excludes heat recovery steam system and steam turbine).

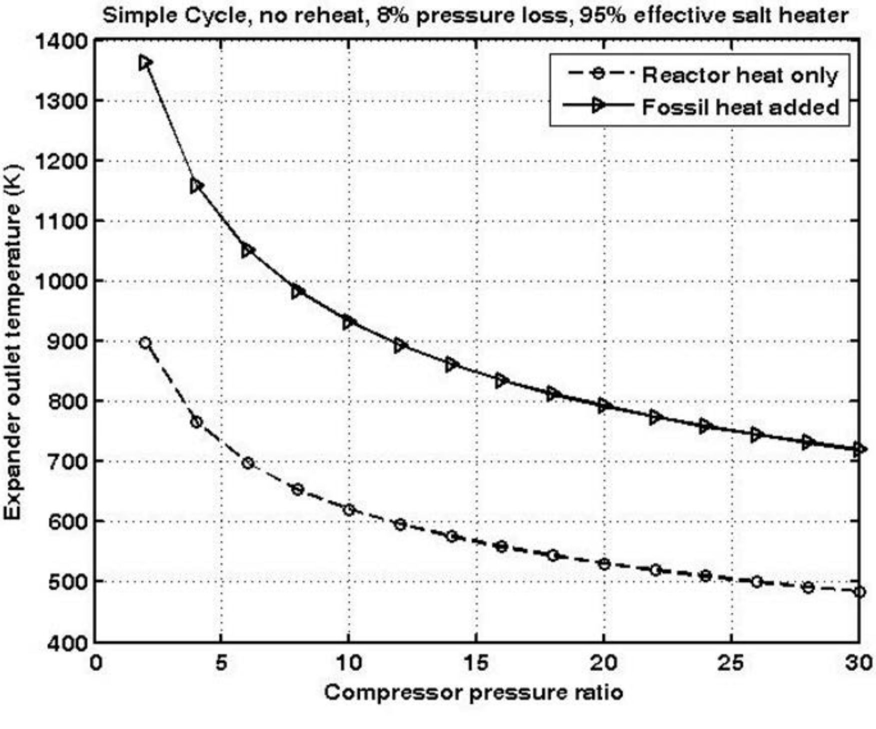

FIG. X–3. Gas turbine outlet temperature versus compressor pressure ratio.

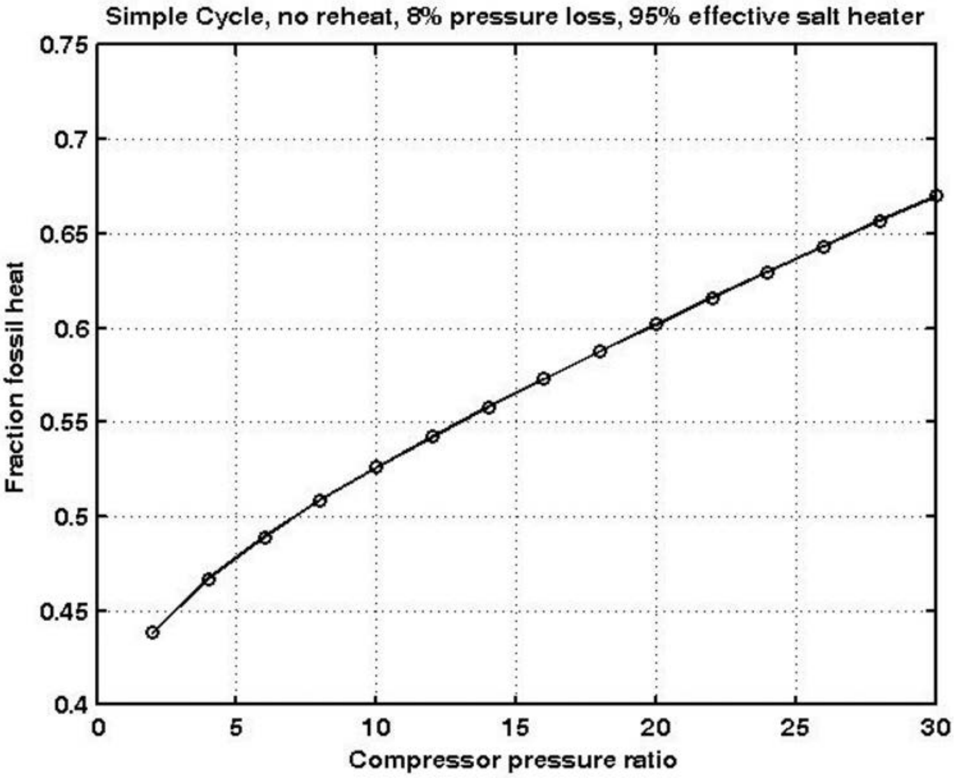

FIG. X–4. Fractional burner heat versus compressor pressure ratio.

For the case of reactor heat only, the pressure ratio for maximum power is 8, and for maximum efficiency, it is 12. When additional heat from the burner is added, the maximum power pressure ratio increases to 16, and the maximum efficiency occurs at a pressure ratio greater than 30. Figure X–2 shows the profound effect of turbine inlet temperature on the efficiency and specific power, but it also demonstrates the noticeable effect of pressure ratio. For the postulated use of this combined cycle machine, these results are promising because the pressure ratio yielding the maximum efficiency when operating under reactor heat (baseload) also yields a maximal amount of power when burner heat is added (peak load). In addition, some of the existing designs of combined cycle gas turbine power plants currently operating on the grid have compressor pressure ratios of ~15.

An important result for the combined cycle is the gas turbine exhaust temperature, which is the inlet temperature to the HRSG of the bottoming Rankine steam cycle. In Fig. X–3, this temperature is plotted as a function of compressor pressure ratio for the two cases of unfired (baseload) and fired (peak load) heat addition.

It should be noted that the gas turbine exit temperature from reactor heat only (baseload), operating at the pressure ratio from Fig. X–2 for maximum thermal efficiency, is 600 K (327°C). This temperature is similar to steam temperatures from light water reactors, but is low compared with peak steam temperatures from fossil power plants. At these temperatures, the steam pressure would be limited in the steam generator to 12.3 MPa. The gas turbine exit temperature for the fired (peak load) case at the pressure ratio from Fig. X–2 for maximal power would be ~825 K (552°C), which would increase the allowable pressure in the steam generator for additional Rankine cycle power. The effect of this exit temperature on the power generated by the steam Rankine portion is presented in Section X–5.2.

Another result of interest for the combined cycle is the fractional amount of the total heat transferred to the compressed air by the combustor during operation, as shown in Fig. X–4. For the maximum efficiency pressure ratio of 12, 54% of the total heat is provided by the burner, and 57% for the maximal power pressure ratio of 16. This increasing fraction is due simply to the increase in compressor exit temperature as the pressure ratio increases since the unfired temperature remains limited by the salt to air heat exchanger.

X–5.2. Steam turbine cycle model

The steam turbine cycle portion of the proposed combined cycle has two interrelated subsystems: the HRSG and the steam turbine. In modelling the HRSG, the simplest configuration to use was that of a simple heat balance of the gas side and the water side. The gas turbine outlet conditions of mass flow and temperature specify the HRSG gas side mass flow and inlet temperature. To complete the gas side of the HRSG, a stack temperature of 120°C was specified in order to exhaust the water content as a vapour and avoid wet stacking. Air ambient temperature was also specified as a parameter of the gas turbine inlet conditions. The corresponding inlet and outlet temperatures of the water side were specified as approach temperature differences of the gas side temperatures.

The HRSG outlet temperature and flow are set equal to the steam turbine inlet temperature and flow. The shaft power extracted by the steam turbine is simply the product of the steam mass flow, the isentropic enthalpy change from the inlet conditions to the condenser conditions, and the adiabatic efficiency of the turbine.

For simplicity, only one pressure level was modelled in the HRSG where only the approach temperatures were specified. One important parameter of steam generator design is the pinchpoint, or closest approach between the hot gas temperature process line and the water steam temperature process line. The value of the pinchpoint minimum temperature difference was monitored to ensure physically realistic values. The steam turbine model was also as simple as possible, where only the exit steam quality need be specified. In addition, no regenerative feedwater heaters (i.e. no steam extraction during expansion) were modelled. Owing to this simplistic approximation of no feedwater heating, the efficiencies calculated will be lower than those resulting from the more common and realistic feedwater heater regeneration train configuration. This very simple model should be improved in the future, as this study is just a first step in a feasibility analysis of the concept.

During these parameter studies, various seemingly physically realistic HRSG approach temperatures and turbine exit qualities resulted in pinchpoints approaching zero, which would result in a very large HRSG. Indeed, some parameters resulted in physically unrealistic negative pinchpoint temperature differences. This close approach pinchpoint is definitely a problem in combined cycle HRSG design because, usually, a high evaporating pressure is desired to increase the power of the turbine. This high evaporating pressure with its concomitant high evaporating temperature, however, results in a small pinchpoint that requires a large heat transfer area with resulting high manufacturing costs. This pinchpoint was monitored during parameter variations, as well as the effectiveness of the HRSG. If either were physically unrealistic, a cycle parameter was changed until these were reasonable.

Another parameter of importance is HRSG effectiveness, defined as the actual heat transfer divided by the theoretical maximum heat transfer. An effectiveness of unity represents a heat exchanger of infinite extent, so this effectiveness must be less than one for physically realistic heat exchangers. One simplistic modelling assumption was that the HRSG approach temperatures used in computing the HRSG effectiveness were specified for both the AHTR (baseload) and fossil (peak load) operating conditions. An improved modelling assumption would be to specify the physical (and heat transfer) size of the HRSG and then analyse the heat transfer process in order to compute the actual approach and pinchpoint temperatures for all power levels. However, for the purposes of this study, the simplistic assumption of specified approach temperatures was appropriate.

The thermophysical properties of water were computed by the algorithms of the IFC1997 formulation, and the air and combustion gas properties were computed using those of Colonna and Silva [X–13].

X–5.3. Baseload and peak load power results

Initial studies indicate that the gas turbine conditions will be similar to the existing GE model MS7001FA gas turbine in terms of gas pressure ratios and peak temperatures. The operating points for baseload electricity production are near the peak efficiency operating conditions for the gas turbine at the lower inlet temperatures, whereas the operating points for peak power production are near the maximum power output condition for the gas turbine at the higher inlet temperatures. A combined cycle system was simplistically modelled with a single gas turbine having the same pressure ratio and gas flow rates as the GE turbine and a steam cycle representative of the commercial GE combined cycle machine.

The calculations showed a baseload power output (both gas and steam turbine) of 68.0 MW(e) and a peak load power output of 276.1 MW(e). For baseload operations, the reactor provides 175 MW(th) at 800°C. For peak power production, the fossil fuel provides an additional 323 MW(th) at a peak gas turbine inlet temperature of 1300°C.

The parameters chosen are listed in Table X–1.

TABLE X–1. PARAMETER LISTING

Parameter	Peak (nuclear + fossil)	Base (nuclear only)
Gas turbine compressor polytropic efficiency (%)	85	85
Gas turbine polytropic efficiency (%)	90	90
Steam turbine adiabatic efficiency (%)	90	90
Steam turbine exit quality (%)	100	90
Ambient temperature (°C)	10	10
Condenser approach temperature difference (°C)	10	10
HRSG hot side approach temperature difference (°C)	30	30
Gas turbine inlet temperature (°C)	1300	780
Gas turbine air mass flow rate (kg/s)	445	445
Compressor pressure ratio	16	16
Gas turbine pressure loss (%)	8	8

Note: HRSG: heat recovery steam generator.

As shown in Table X–2, the computed performance using these parameters was reasonable, and was typical of currently existing fossil fuel combined cycle machines. For Table X–1, it should be noted that the computational model used is simple (e.g. no feedwater heaters). Based on this comparison, this simple model yields sufficiently accurate values for the purposes of these scoping studies.

TABLE X–2. CALCULATED RESULTS AND COMPARISON

Parameter	Peak (nuclear + fossil)	Base (nuclear only)
HRSG effectiveness (%)	85	62
HRSG pinchpoint (°C)	25	16
HRSG evaporating pressure (MPa)	1.5	0.27
Compressor exit temperature (°C)	426.5	426.5
Gas turbine inlet temperature (°C)	1300	781.5
Gas turbine outlet temperature (°C)	626	283
Gas turbine power (MW)	188.5	50.2
Steam turbine inlet temperature (°C)	596	253
Steam turbine outlet temperature (°C)	20	20

TABLE X–2. CALCULATED RESULTS AND COMPARISON (cont.)

Parameter	Peak (nuclear + fossil)	Base (nuclear only)
Steam turbine power (MW)	83.6	17.8
Total power (MW)	272.1	68.0
Gas turbine thermal efficiency (%)	37.9	28.8
Steam turbine thermal efficiency (%)	29.0	14.3
Total thermal efficiency (%)	54.7	39

Note: HRSG: heat recovery steam generator.

During these computations, the pinchpoint temperature difference was very sensitive to the specified turbine exit quality. When quality values of 90 and 95% were tried, close or negative pinchpoint temperature differences were calculated, the results of which were, of course, discarded. The increased evaporator pressure resulting from the wet turbine exhaust, which is desirable, unfortunately set up the undesirable low or negative pinchpoint. This pinchpoint problem is, and has always been, a concern in HRSG and steam turbine design.

Another parameter of importance identified during the model evaluations was the moisture content of the exhaust. As the compared gas turbine used methane as the fossil fuel, the exhaust would have contained moisture as a result of combustion. For the lean conditions postulated here, this moisture represented ~10% of the exhaust gases. This moisture content added power from the gas turbine by increasing the specific heat by 20%. This increased gas flow capacity rate also advantageously increased the pinchpoint temperature difference in the HRSG. During postulated operation with heat only from the AHTR, the gas turbine power will decrease, and the pinchpoint will decrease when this combustion moisture is not present.

X–5.4. Alternative power cycles

Future studies will examine alternative combined cycles. A wide variety of system configurations exist to boost baseload to peak load power levels, boost efficiency or increase the nuclear heat fraction when the plant is operating in a peak power production mode. However, these configurations have not yet been analysed. Two interconnected factors will determine the optimum combined cycle. Electrical grid characteristics will partly determine the desired relative output of baseload versus peak load power. The power plant capital cost will also influence design. The nuclear plant has high capital costs and will, thus, operate at baseload conditions. Consequently, the economic trade-offs in the power cycle during baseload operation will be optimized for capacity factors near 90%. In contrast, the economic trade-offs in the power cycle design during peak load operation are optimized based on operating 10–50% of the time. The economic optimum design for peak power production will likely be at somewhat lower peak efficiency in exchange for lower initial capital costs.

Examples of alternative configurations include: (i) steam injection into the gas turbine after air compression but before nuclear heating (increased baseload versus peak power production); (ii) heating HRSG steam using nuclear heat to temperatures found in advanced steam plants (increased nuclear baseload efficiency and output); or (iii) interstage cooling in the air compressor (increased capital cost for increased efficiency under baseload conditions).

X–6. MARKETS

The capital and operating costs of different power generation technologies determine in which markets particular technologies are competitive. The NCCC plant has an unusual cost structure. The nuclear baseload component of the plant will have high capital costs, but low operating costs, similar to those of other nuclear plants.

The peak load component of the plant is a modified combined cycle plant with low capital costs per kW(e) of capacity — similar to traditional natural gas combined cycle plants that have estimated costs of ~570 \$/kW(e)·h. However, the operating costs will be much lower than those of traditional natural gas fired combined cycle plants. Some of the heat is low cost nuclear heat, and some of the heat is at a higher cost (natural gas, jet fuel or hydrogen). The other unique characteristic is the ability to alter power output very rapidly, far more rapidly than any fossil electric generating technology. This creates a unique set of markets for NCCC plants.

X–6.1. Premium markets

For a combined cycle plant with electricity sold to the electrical grid, three premium electrical markets [X–13] exist in which the value and price of electricity far exceed the price of baseload electricity (Table X–3).

TABLE X–3. PREMIUM POWER GRID ELECTRICAL MARKETS IN THE USA [X–14]

Technology parameter	Regulation	Spinning reserve	Load shifting and load levelling
Capital cost (\$/kW)	700	300–1000	300 (load levelling) 400–1000 (peak shaving and load shifting) 650 (renewables)
Total market potential (GW)	30–40	70–100	80 (cost sensitive)
System power level	Up to 200 MW	10 MW–1 GW	1 MW–1 GW
Discharge time at rated power	Seconds to minutes	0.2–2 h	1–8 h
Lifetime (years)	20	40	7–10

X–6.1.1. Regulation

Electric consumers turn equipment on and off with switches that operate in a fraction of a second. Electrical generators can vary the power output over a period of minutes. If the demand and generation do not match, the system frequency and voltage change. However, if the changes are too great, both customer and utility equipment is damaged. Ultimately, the system can fail, with a resultant blackout. The electrical system works because the electrical grid averages demand over many customers, so that the generators do not experience rapid changes in power demand. As a consequence, larger electrical grids are more stable, have higher quality electricity (proper voltage and frequency) and are more reliable than smaller electrical grids.

As the stability of many electrical grids is decreasing, better methods are required to ensure grid regulation and delivery of high quality electricity. This situation is partly a consequence of the growing electricity demand associated with electronics. With traditional electrical loads, such as incandescent light bulbs, if the line voltage drops (insufficient power generation), both the electrical current and the power demand drop. This provides time for the electrical generators to speed up or slow down as required to match power production with power demand. However, with many electronic devices, as the voltage drops, the device demands more current, and the power demand goes up. Hence, the system provides less time for electrical generators to respond to the demand. The system becomes more prone to failure, and the quality of electricity decreases.

Figure X–5 shows the variations in demand for 1 day on the Texas utility grid and the rapid variations in power demand over 1 h [X–15]. This figure shows the rapid change in electrical demand that can occur, partly caused by changing electrical load and partly by the changing frequency and voltages on the grid. There are strong incentives to reduce these short term variations by better grid regulation.

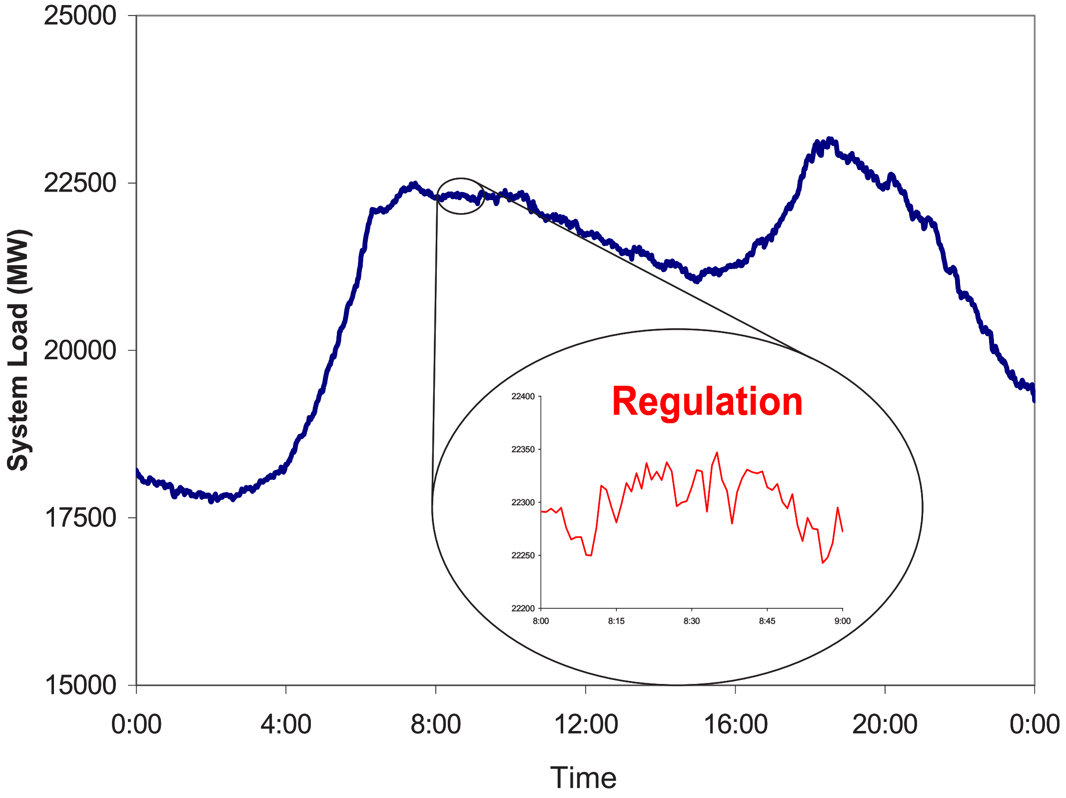

FIG. X–5. A typical electrical power demand load on the Electric Reliability Council of Texas electrical grid over a 24 h period on a winter's day [X–15].

Owing to its rapid response time, the NCCC plant can potentially be used to provide electricity for this variable electrical demand and, thus, produce higher quality electricity (constant voltage and frequency) and provide the time for other power generation units to increase or decrease their electrical output. The time period varies from seconds to tens of minutes, depending upon the electrical grid size as well as other factors. In small grids where there are fewer customers and less load averaging, the demands for power regulation are more severe. In this mode of operation, the NCCC plant would operate continuously at some power level (hot and spinning), with the power levels varied as required. The allowable capital cost for this capability (Table X–3) significantly exceeds the incremental peaking capability costs for the NCCC plant.

X–6.1.2. Reserve power (spinning reserve)

Reserve power provides generating capacity in the event that an electrical generator goes off-line for unexpected reasons. Presently, such a situation is handled by putting on-line additional power plants that run at partial load with the capability to produce more power if another unit goes off-line. However, this process represents expensive backup power. An NCCC plant could potentially provide spinning reserve by operating at low power levels with the capability to rapidly go to peak power. For this application, high power output must be provided for periods of time ranging from tens of minutes to a few hours — the time required to start up another power generation system. The allowable capital cost significantly exceeds the incremental spinning reserve capability cost for an NCCC plant.

X–6.1.3. Load shifting and load levelling

The demand for electricity varies by the time of day, the week and the season. The cost and price of electricity are high at times of peak power demand and low at times of low power demand. The high cost of peak power reflects the fact that the facilities required to produce much of this power are operated for only a few hundred or a thousand hours per year, as shown in Table X–4, which lists the marginal prices of electricity in 2004 for nine US electrical grids [X–16]. The table shows the number of hours per year that electricity could be bought or sold for a particular price range in \$/MW(e)·h. The prices of electricity for a few hours per year can be much higher. For example, the Texas grid (Electric Reliability Council of Texas) has had spot market prices as high as \$1500 MW(e)·h.

TABLE X–4. 2004 ELECTRICITY PRICES VERSUS NUMBER OF HOURS FOR DIFFERENT ELECTRICAL GRIDS [X–16]

	Hours per year								
\$/MW(e)·h	Seattle	ISO New England	Southern	Arizona Power Station	Florida P&L	AEP	LADWP	Com. Edison	PJM
<5	—	69	—	7	—	19	3	406	106
5–10	170	9	—	—	—	32	9	229	59
10–15	513	11	—	4776	50	3155	1470	1105	141
15–20	1866	31	238	700	425	3014	67	2734	479
20–25	1111	157	887	65	83	1112	88	981	761
25–30	522	260	1342	126	89	360	374	694	1060
30–35	1619	391	1902	560	916	307	489	863	1067
35–40	981	797	1658	614	1645	271	386	438	1093
40–45	627	1256	1826	588	1641	175	657	311	819
45–50	508	1479	378	462	1343	97	1506	273	691
50–55	341	1314	83	358	1166	67	1859	181	531
55–60	309	1028	87	268	671	41	1089	163	449
60–65	147	651	88	186	399	25	516	109	358
65–70	25	429	96	53	159	21	165	86	275
70–75	30	285	86	15	77	21	66	69	224
75–80	15	186	45	2	59	11	3	45	176
80–85	—	107	33	1	20	11	17	32	145
85–90	—	82	13	1	15	9	15	22	103
90–95	—	61	18	—	6	11	5	13	72
>95	—	181	4	2	20	25	—	30	175
Total hours	8784	8784	8784	8784	8784	8784	8784	8784	8784

Note: AEP: American Electric Power; Com. Edison: Commonwealth Edison Co.; ISO: International Organization for Standardization; LADWP: Los Angeles Department of Water and Power; P&L: Power and Light; PJM: Pennsylvania, New Jersey and Maryland.

Large differences in the cost of electricity versus time occur across the country, and significant quantities of electricity are sold at high wholesale prices in such grids as ISO New England, Florida Power and Light, and Pennsylvania, New Jersey and Maryland. In any of these markets, an NCCC plant has the potential to provide lower cost peak power.

In a number of markets, an NCCC plant using electrolysis for hydrogen production could be potentially competitive when low cost electricity is used to produce hydrogen and the electricity is sold during periods of high electricity costs. Generally, the price of electricity at peak times must be several times that of input electricity for break-even economics to occur because of the round trip efficiency of electricity to hydrogen and back to electricity. The fact that different markets have different characteristics must also be considered. For example, electricity prices for the Los Angeles Department of Water and Power show low priced electricity (\$10–15/MW(e)·h) for almost 1500 h/a, but high priced electricity (over three times higher) for over 5000 h/a. This double hump price curve reflects the low night time demand and the high daytime demand for electricity in Los Angeles. If an NCCC plant with hydrogen production were used in this system, the required hydrogen storage volumes would be equal to those required to cover day–night shifts and weekday–weekend shifts in electricity demand. The electricity prices for Seattle Power and Light show a similar double hump curve, but the situation is much different. The utilities in the Pacific north-west have large quantities of hydroelectric power that make it inexpensive to meet the variable daily demand for electricity. However, the utilities have excess electricity in the spring, when water from the snow pack is dumped over the dams or through the generators to produce electricity. In contrast, in late autumn, the hydroelectric power production is low because the snow pack has melted and water flows have decreased. Fossil units with high operating costs are used to meet the power demand during this time of year. If an NCCC plant were used in these systems, the hydrogen storage volumes would be seasonal, reflecting the seasonal characteristics of power costs in the north-west.

X–6.2. Small grid markets (including developing countries)

Small electrical grids, such as those in developing countries, present difficult operating and economic challenges. Large electrical grids create an electrical demand that is averaged over millions of customers. A single customer turning equipment on or off has little impact on the total electrical demand. Similarly, a single power plant only produces a small fraction of the electric generation, and thus would have a limited impact on the electrical grid if it were to shut down. A large grid, as measured in customers and power generation units, implies slow changes after a major customer shuts down or a single generator goes off-line. The changes in voltage are small, and high quality electrical power can be delivered. Equally important, the large number of different generating units allows careful dispatch of the lowest cost units to provide electricity.

In contrast, in a small grid, the changes in the demand for electricity of just a few large customers have large impacts on the total demand for power and power quality (voltage, phase and frequency). Similarly, the loss of a single generating unit can cause large grid disturbances because that unit represents a significant fraction of the total electricity generating capacity. For the same level of equipment reliability and operator skills, a small grid will have more blackouts, lower quality power (voltage variations) and higher costs. To achieve the same levels of reliability and power quality, a much higher spinning reserve capability is required as a fraction of the generating capacity of the grid.

The requirement to accommodate variable load and provide more spinning reserve to ensure grid stability implies that a nuclear plant in a small electrical gird will likely operate at variable load. However, the economics of traditional baseload nuclear plants are poor if these plants must operate at variable load to meet grid requirements. In addition, it is difficult to integrate a baseload nuclear power plant into a small grid unless the grid already has a large hydroelectric component.

For small electrical grids, such as those in developing countries, an NCCC plant may be the enabling technology for use of nuclear energy by providing baseload electrical power, peak load electrical power and a method to stabilize the electrical grid to produce high quality electrical power. The unique rapid response capability provides a method for stabilizing the grid when a major customer comes on-line or another generating unit goes off-line for any reason. The peaking capability can provide a low cost reserve margin for the grid. It may also be the enabling technology that will allow small grids to produce the same high quality power found in large electrical grids.

X–6.3. Greenhouse impacts

Concerns about climate change may result in constraints on the releases of greenhouse gases to the atmosphere. Major programmes are under way to develop methods to sequester carbon dioxide in geological structures. Recent assessments [X–17] indicate that sequestration may increase busbar electrical costs by up to 40% for baseload power production systems. However, the costs for carbon dioxide sequestration for fossil fired peak power units will be much higher. These units operate only a limited number of hours per year; thus, the capital cost component of the cost of electricity is much greater per kW(e)·h. Consequently, any restrictions on greenhouse gas releases would significantly improve the relative competitive advantage of an NCCC plant that produces and uses hydrogen.

X–7. REACTOR AND INTERMEDIATE HEAT TRANSPORT LOOP OPTIONS

X–7.1. Reactor options

The NCCC requires a high temperature reactor, so that the compressed air, after nuclear preheating, is above the auto-ignition temperature of the fuel. This implies, after accounting for temperature drops across intermediate heat transport loops, peak temperatures of ~700°C for the reactor. Several different high temperature reactors can potentially be coupled to this power cycle:

- Molten salt reactors (MSRs): MSRs are liquid fuel reactors that were originally developed for the Aircraft Nuclear Propulsion programme of the 1950s, and were to be coupled to jet engines. Two small test reactors were built. Since that programme, there have been major developments in Brayton power systems, but only limited development of MSRs. The MSR is a longer term reactor option for an NCCC plant.
- High temperature gas cooled reactors (HTGRs): HTGRs are helium cooled reactors that use solid coated particle fuels. Several HTGRs have been built, and several programmes are under way to commercialize this reactor [X–5], including the Next Generation Nuclear Plant programme of the United States Department of Energy. The HTGR is a realistic candidate for an NCCC plant.
- AHTRs: The studies herein have coupled the NCCC plant to an AHTR. AHTRs are proposed liquid salt cooled high temperature reactors [X–4] that use the same coated particle fuels as those that are used in helium cooled high temperature reactors, and are currently under development. As AHTRs are liquid salt cooled reactors, their characteristics, as seen by the NCCC plant, appear identical to those of MSRs — the reactors originally developed for nuclear jet engines. (The fundamental difference between the MSR and the AHTR is that the MSR dissolves the fuel in the salt coolant, whereas the AHTR uses a solid fuel and a clean salt coolant.)

X–7.2. Intermediate heat transport loops

Heat must be transported from the high temperature reactor to the combined cycle plant using an intermediate heat transport loop. The intermediate heat transport loop isolates the reactor coolant from the air Brayton power cycle to ensure that fission products are not transported from the reactor to the environment. At high temperatures, this includes preventing migration of tritium from the reactor to the environment. The intermediate loop also isolates the NCCC plant from the reactor. It ensures that fires or other accidents with fossil fuels or hydrogen cannot impact nuclear plant safety. It also allows the power generation equipment to be outside the high security envelope of the reactor. This has significant cost benefits.

There are several candidate fluids (about five) for the intermediate heat transport loop: inert gases including helium, noble gas mixtures, helium nitrogen mixtures, liquid metals such as sodium and potassium, and liquid salts. Multiple experiments and engineering studies are under way in the USA and elsewhere on the coupling of high temperature reactors to hydrogen production plants and other chemical plants. The requirements for heat transport from a high temperature reactor to a hydrogen plant are somewhat similar to heat transport from a high temperature reactor to an NCCC plant. Consequently, those studies will provide much of the basis for engineering studies to choose the optimum heat transport fluid for this specific application.

X–8. TECHNOLOGY CHALLENGES

Most of the component technologies for an NCCC power system exist in commercial form. High temperature reactors have been developed and built, but they are not yet a commercial technology. In terms of the power cycle, there are several significant remaining challenges:

- System structure: There are multiple possible NCCC power system configurations. System studies are required to determine which configurations will be preferred.
- Nuclear heat exchanger: The heat transport loop between the reactor and the NCCC power cycle must be developed. This includes comparison and selection of the best heat transfer fluid for this application.
- Integrated design: Designs for an integrated NCCC power system must be developed and tested. However, there is one major challenge to creating these designs that will require significant work. Since their development in the 1930s, gas turbines have been designed with the constraint of matching the air to fuel ratio to ensure flame stability and complete combustion. In an NCCC system, this constraint is removed. The air compressor in an NCCC system is powered by nuclear heat only, and this, in principle, allows for very rapid increases in turbine power levels relative to traditional gas turbines. In such a system, there is no need to speed up the compressor, and the fuel is injected into hot air above its auto-ignition temperature. However, this is a design space where there has been little analysis and no significant testing.
- Hydrogen fuel options: The option of hydrogen fuel is only partly understood. Significant system studies are required. Work is under way to develop all of the required technologies as part of various hydrogen initiatives worldwide.

X–9. CONCLUSIONS

The NCCC power plant is a new concept in power plant design that combines the advantages of nuclear power plants and traditional fossil fired combined cycle plants. A first level analysis of the concept has been completed that indicates technical viability and potential economic competitiveness in specific markets. Such a power system reactor has multiple potential advantages:

- Premium electrical markets: The rapid response capabilities of this system may allow nuclear energy to enter the premium price electricity markets for grid regulation, spinning reserve and load following. Perhaps of greater, but not fully defined, importance, the very rapid response to electrical demand creates a new capability that was not previously available for ensuring high quality electricity on the grid. The use and value of this potentially new capability is not yet fully understood.
- Small reactors for small electrical grids: The developing world has small electrical grids with highly variable electrical loads. There is a requirement for reactors that are economical and can load follow. The capability to rapidly respond to changes in power demand may allow this system to be used for spinning reserve, frequency control and voltage control — major operational problems in small electrical grids with a small number of generating units. It may also improve grid reliability by providing a system that can rapidly respond to loss of other electrical generating units (spinning reserve). As a secondary benefit, the NCCC power cycle is a derivative of traditional natural gas combined cycle plants that are used in many developing countries — a power cycle these utilities are familiar with.
- Reduced carbon dioxide emissions: Fossil fuels are universally used to provide peak electrical power because (i) they are storable and (ii) the cost of equipment to convert the fuel to electricity is low relative to the cost of the fuel. A long term constraint is the release of greenhouse gases. For peak power production, the nuclear heat preheats the air approximately halfway to its peak temperature and, thus, can reduce by up to a factor of two the use of fossil energy for peak electrical production. If hydrogen replaces the natural gas or jet fuel, an NCCC system can provide peak electricity without production of greenhouse gases.
- Improved economics: The system has the potential for improved economics by combining low cost baseload nuclear heat production that allows full utilization of the nuclear heat source with peak power production using low capital cost combined cycle systems.

— Available technology: Most of the power conversion technology is existing technology that can be coupled to high temperature reactors. Thus, the development of high temperature reactors is not coupled to development of new power conversion systems — except for the nuclear heat exchanger.

— Higher efficiency: Gas turbines, with technologies such as actively cooled hollow blades, can operate at much higher temperatures than nuclear reactors. The NCCC system allows operations to be conducted at higher temperatures and, thus, higher efficiencies than nuclear only systems.

A significant amount of additional work will be required to understand both the advantages and disadvantages of this technical concept. There are significant technical uncertainties. The NCCC does require a high temperature reactor so the compressed air after nuclear preheating is above the auto-ignition temperature of the fuel. Several different high temperature reactors can potentially be coupled to this power cycle.

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Annex XI

POTENTIAL MARKETS FOR SMALL REACTORS

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XI–1. SUMMARY

The electricity cost of a small power generation plant is generally higher than that of a large scale power plant due to economies of scale. In order to survey the market for small nuclear power plants, the competitive object is not a large scale power plant but a small fossil fuel power generation plant. Large scale power generation plants are not required in all countries and regions of the world. There are many regions where the electricity cost is high because of the cost of fuel transport to remote places. Medium or small power generation plants could turn out to also be preferable from the viewpoints of electrical power demand and distribution cost. For example, the electricity costs in many small cities or towns of the Alaskan and Hawaiian Islands are higher than on the mainland. The electricity costs in the two peninsulas (Baja California and Yucatan) in Mexico are high because, owing to the limited power demand in these regions, small and medium sized fossil fuel power generation plants have been installed there, and the costs of fuel, fuel transport and power transmission appear to be relatively high.

Owing to such situations, a market for small and medium sized nuclear reactors exists, and there are certain regions and areas in the world where such reactors can compete with the alternatives.

XI–2. INTRODUCTION

The cost of electricity from small nuclear plants is relatively high because of the lack of economies of scale. However, owing to the achievements of a standardized design, factory fabrication and assembling, mass production and a reduction of work on the site, a decrease in the construction cost of each single unit of a small reactor is possible. The effect of mass production could be similar to that observed in the aircraft industry, such as for the Boeing 777. If a small reactor also has passive safety features, long life fuel, simple operation, etc., further cost reductions could be possible.

In a previous study [XI–1], opportunities for the deployment of small reactors intended for a worldwide market were investigated, by country and region. This annex presents an analysis of how the small reactor business might get started, focusing on the deployment of a first small reactor, before mass production is achieved. The size of a small reactor in this annex is taken to be 50 MW(e).

XI–3. MARKET SELECTION

Four categories of opportunity for small reactors were identified in the previous study [XI–1]:

- Category 1 includes countries that might be a starting point for the deployment of a small reactor; these countries are Argentina, Egypt, Indonesia, Mexico, Tunisia and Uruguay.
- Category 2 is represented by the states of Hawaii and Alaska in the United States of America (USA); these states have remote areas or island communities, and the power cost is high there.
- Category 3 includes countries in Central America that are actively expanding their power grids, but have not demonstrated great interest in the nuclear power option, probably because they do not require large power plants.
- Category 4 represents a broad group of developing countries for which further study is required. They represent a large market that may become available when there is a proven power system with a small reactor.

Certain details related to some of these categories are discussed in the following.

XI–4. SELECTED COUNTRIES WITH HIGH ELECTRICITY COSTS

The first several units of a small reactor could be built in countries or regions with high electricity costs because cost reduction still cannot be achieved by mass production. The effects of mass production to reduce electricity costs would appear after the construction of the first 100 units (construction of ten units per year over 10 years), as has been evaluated in a previous study [XI–2]. There are many countries where electricity costs are high and the installed total capacity is small [XI–3]. In these countries, medium or large sized nuclear power plants cannot be deployed because of restrictions related to the electrical system control. From this standpoint, the maximum capacity that can be installed in the electrical system should generally not exceed 10% of the total installed capacity. If the size of a small reactor is 300 MW(e), only one unit can be built and only in one of the countries shown in Table XI–1. If the size of a small reactor is 50 MW(e), then about 30 units with such reactors could be built in the countries shown in Table XI–1. Several units of small reactors of 50 MW(e) could be built in countries where the electricity cost is high.

TABLE XI–1. ELECTRICITY COSTS FOR HOUSEHOLDS ON SEVERAL ISLANDS AND IN COUNTRIES WITH SMALL OVERALL GENERATION

Country	Electricity cost ($/kW·h) (2003)	Installed total capacity (MW(e)) (1995)	5% of total capacity (MW(e))	10% of total capacity (MW(e))
Kiribati	0.25 (1998)	5	0.25	0.5
Maldives	0.22	5	0.25	0.5
Grenada	0.223 (1994)	13	0.65	1.3
Nauru	0.066 (1998)	14	0.7	1.4
Solomon Islands	0.11 (1998)	21	1.05	2.1
Guyana	0.06	110	5.5	11
Haiti	0.068	150	7.5	15
Barbados	0.204	152	7.605	15.21
Fiji	0.11 (1998)	200	10	20
Honduras	0.076	290	14.5	29
Mauritius	0.09 (1998)	340	17	34
Brunei Darussalam	0.14 (1996)	380	19	38
Suriname	0.171	420	21	42
Nicaragua	0.118	460	23	46
Papua New Guinea	0.097 (1998)	490	24.5	49
Cyprus	0.09 (1997)	550	27.5	55
Guatemala	0.079	700	35	70

TABLE XI–1. ELECTRICITY COSTS FOR HOUSEHOLDS ON SEVERAL ISLANDS AND IN COUNTRIES WITH SMALL OVERALL GENERATION (cont.)

Country	Electricity cost ($/kW·h) (2003)	Installed total capacity (MW(e)) (1995)	5% of total capacity (MW(e))	10% of total capacity (MW(e))
Jamaica	0.146	730	36.5	73
El Salvador	0.082	750	37.5	75
Bolivia	0.066	756	37.81	75.62
Albania	0.03 (1997)	770	38.5	77
Panama	0.121	960	48	96
Costa Rica	0.065	1040	52	104
Iceland	0.17 (1992)	1070	53.5	107
Trinidad and Tobago	0.028	1150	57.5	115
Luxembourg	0.098	1239	61.95	123.9
Sri Lanka	0.068 (1998)	1410	70.5	141
Dominican Republic	0.087	1450	72.5	145
Uruguay	0.137	2070	103.5	207
Ecuador	0.055	2230	111.5	223

The electricity cost for a household on the selected island areas is shown in Table XI–2 [XI–3]. The maximum cost is $0.25/kW·h in Kiribari, and the minimum is $0.025/kW·h in Indonesia. The average electricity cost on these islands is $0.121/kW·h. These electricity cost data provide a target for small reactors that could be installed on the islands.

Even though the electricity cost is higher than for a large power plant, it could be possible to deploy small reactors competitively in these countries.

XI–5. SELECTED REGIONS WITH HIGH ELECTRICITY COSTS

XI–5.1. Alaska

Alaska’s electrical energy infrastructure differs from that in the rest of the USA where, in the lower 48 states, most consumers are linked to a huge, transcontinental electrical energy grid through transmission and distribution lines.

In Alaska, there are at least 175 rural communities that are not interconnected and, therefore, must rely on their own power sources. These communities rely almost exclusively on diesel electrical generators. The high cost of electricity in many areas of Alaska has caused investigations into alternative approaches to electricity generation. These are outlined in the following.

TABLE XI–2. ELECTRICITY COSTS FOR HOUSEHOLDS ON SMALL ISLANDS

Country	Population (July 1998 estimated)	Electricity capacity (MW(e))	Electricity production (kW·h/a)	Electricity consumption per capita (kW·h/a)	Electricity price (¢/kW·h)
Brunei Darussalam	315 292	646 (1997)	1.26 billion (1995)	4 311 (1995)	14 (1996)
Cuba	11 050 729	3 988 (1995)	10 105 billion (1995)	924 (1995)	12.8 (1999)
Cyprus	748 982	666 (1995)	2.6 billion (1995)	3 530 (1995)	9 (1997)
Dominican Republic	7 998 766	1 477 (1995)	6.5 billion (1995)	865 (1995)	9.1 (1999)
Fiji	802 611	200 (1995)	545 million (1995)	705 (1995)	11 (1998)
Grenada	96 217	9 (1995)	70 million (1995)	741 (1995)	19 (1998)
Guyana	707 954	114 (1995)	230 million (1995)	339 (1995)	6.7 (1998)
Haiti	6 780 501	153 (1995)	315 million (1995)	48 (1995)	10 (1999)
Iceland	271 033	1 083 (1995)	4.916 billion (1995)	18 481 (1995)	17 (1992)
Indonesia	212 941 810	16 265 (1995)	60.4 billion (1995)	297 (1995)	2.5 (1999)
Jamaica	2 634 678	1 182 (1995)	3.87 billion (1995)	1 503 (1995)	13 (1998)
Kiribati	83 976	2 (1995)	7 million (1995)	88 (1995)	25 (1998)
Maldives	290 211	14 (1995)	50 million (1995)	191 (1995)	22 (1994)
Mauritius	1 168 256	361 (1995)	960 million (1995)	852 (1995)	9 (1998)
Nauru	10 501	10 (1995)	30 million (1995)	2 956 (1995)	6 (1998)
Papua New Guinea	4 599 785	490 (1995)	1.76 billion (1995)	410 (1995)	9.7 (1998)
Solomon Islands	441 039	12 (1995)	30 million (1995)	75 (1995)	11 (1998)
Sri Lanka	18 933 558	1 557 (1997)	4.86 billion (1997)	220 (1997)	6.8 (1998)
Suriname	427 980	425 (1995)	1.601 billion (1995)	3 727 (1995)	17 (1998)

XI–5.1.1. Small utilities

The Golden Valley Electric Association (GVEA) serves 90 000 interior residents in the Fairbanks, Delta, Nenana, Healy and Cantwell areas. Its generating capability of 228 MW(e) is supplied by five generating facilities, including a 25 MW(e) coal fired plant at Healy, a 120 MW(e) oil fired plant in North Pole, 65 MW(e) at two oil fired plants in Fairbanks, and the 20 MW(e) of the Bradley Lake hydropower facility located near Homer. GVEA's share of Bradley Lake is transmitted via the Railbelt Intertie system. GVEA is the northern control point for the Fairbanks/Anchorage Intertie, which serves most of the Railbelt communities. This transmission system allows the exchange of existing and future generation reserves among the Railbelt utilities and substantially increases system reliability for the Railbelt communities. The Intertie allows GVEA to augment its 228 MW(e) generation capacity with an additional 70 MW(e). Its peak demand was 182 MW(e) in 1999.

XI–5.1.2. Utility costs

The Alaska State Legislature created the Alaska Energy Authority in 1976 to provide affordable power in order to promote and develop the economic welfare of all Alaskan residents. The Institute of Social and Economic Research at the University of Alaska in Anchorage in 2003 issued a report entitled Sustainable Utilities in Rural Alaska [XI–4]. A finding of that report was that:

> "… it costs between \$80 million and \$120 million per year to provide each of the major utilities — electricity, water/sewer, and telecommunications — to rural Alaska consumers. In the case of electricity, fuel, and booked operation and maintenance together account for 59% of total cost. Capital costs carried on utility books account for 15%. The remaining 26% is "off-book" and consists of government-funded capital construction. Government funded O&M assistance accounts for less than 1% of the total true cost of electricity."

The true cost of bulk fuel storage is roughly \$1.50 per delivered gallon (1 gallon = 3.79 L) from the tank with 60¢ of this being for spill response capability. Bulk fuel is expensive because the fixed capital cost is spread over relatively few litres delivered (long storage time). As can be seen from Fig. XI–1, the true non-fuel costs show tremendous variability for the smaller villages [XI–5].

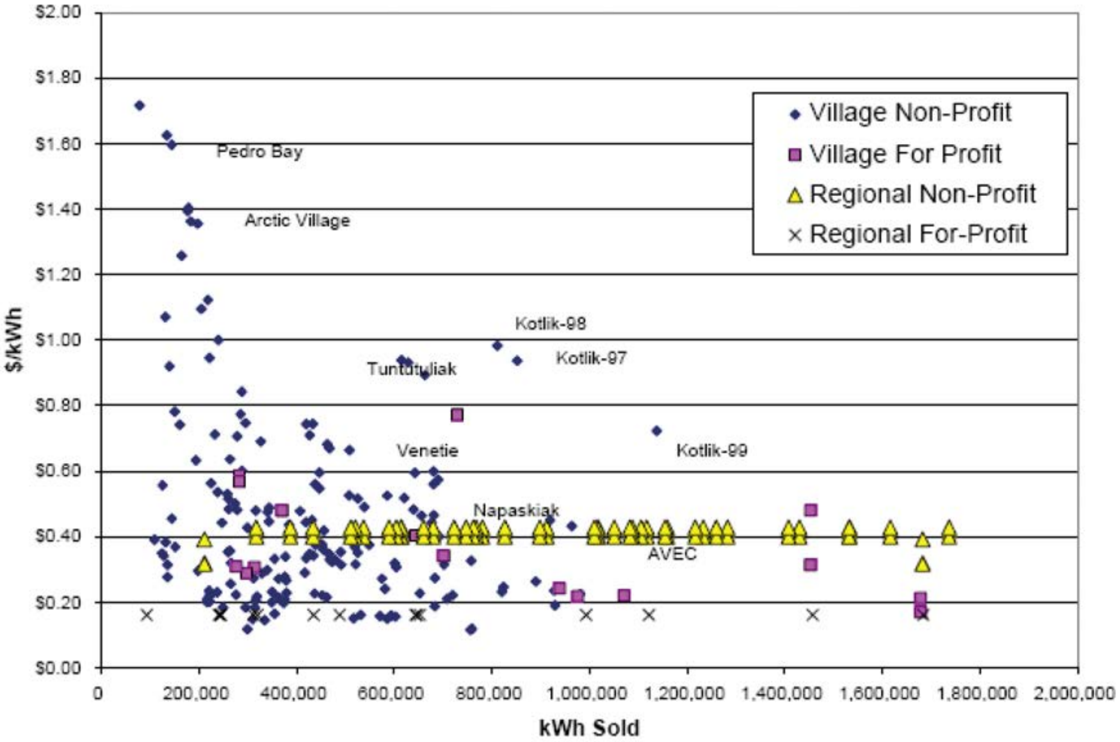

FIG. XI–1. True non-fuel cost of electricity versus annual sales, for different management structures (village level data for places with electric sales of <2 × 10^6 kW·h/a) [XI–5].

XI–5.1.3. Alaska electricity sales by utility in 2000

The average revenue for the residential and commercial utilities is \$0.396/kW·h in the case that the total sales of electricity are below 10 000 MW·h/a; it is \$0.1698/kW·h in the case that the total sales of electricity are over 10 000 MW·h/a [XI–4].

The average electricity costs for residential utilities are shown in Fig. XI–2 for all utilities, and in Fig. XI–3 for small utilities that sell less than 10 000 MW·h/a.

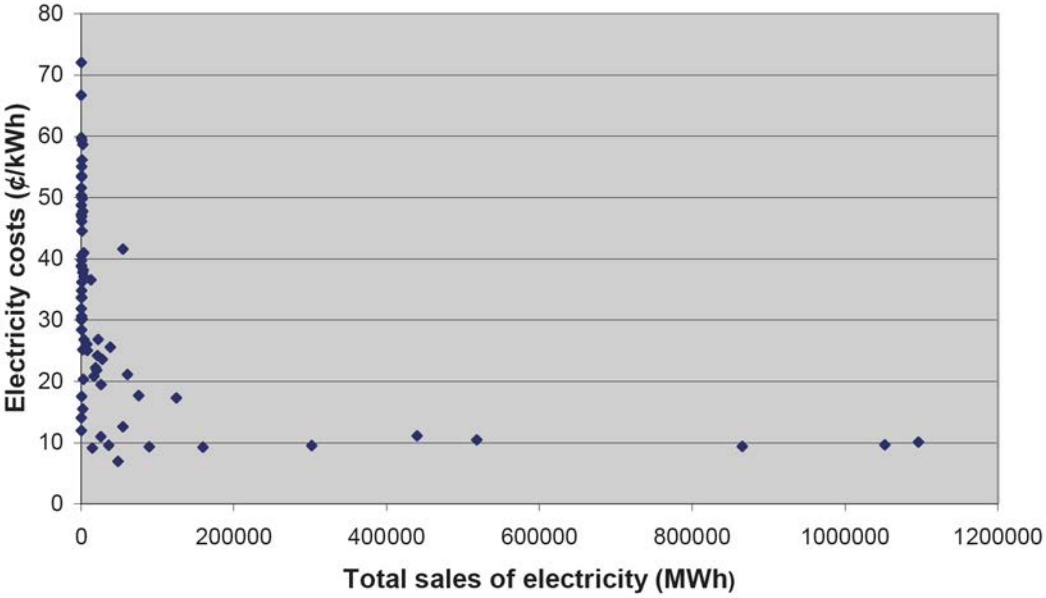

FIG. XI–2. Electricity costs versus sales by utilities in Alaska, 2000.

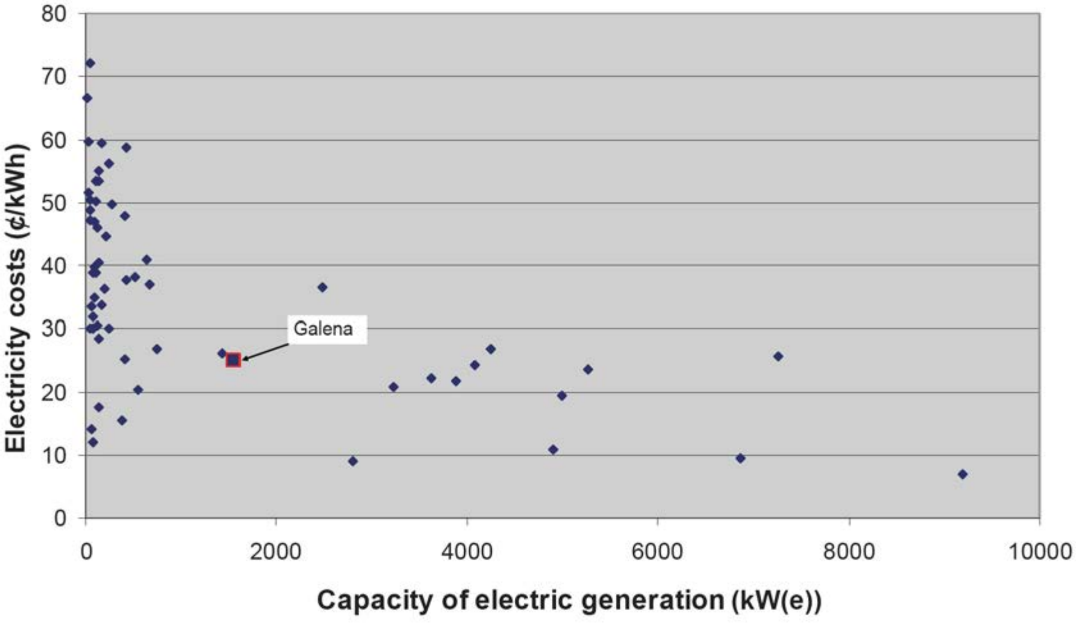

FIG. XI–3. Average electricity costs for small residential utilities (below 10 000 MW·h/a, load factor = 0.6).

The distribution of the average electricity costs for residential units is shown in Fig. XI–4. From Fig. XI–4, it can be seen that several utilities, which are about 10% of the total utilities, can supply electricity at a reasonable price below 10¢/kW·h. More than 50% of the utilities supply very expensive electricity at over 30¢/kW·h. The capacity of those utilities is below 2 MW(e).

Alaska presents an example of the problems faced by small rural communities in obtaining affordable and reliable electrical energy. The cost of operating the current systems is likely to increase to the point that the people will have to move to more affordable locations unless alternatives are identified. There are a vast number of similar rural and island communities in the world. Small reactors may be one of the affordable alternatives. In the case of Alaska, small reactors (with no on-site fuelling) of about 1 MW(e) capacity could be a realistic alternative because more than 50% of the communities pay 30¢/kW·h and do not have solutions for reducing this cost in the future. While the Galena, Alaska, community has already expressed interest in the construction of a small long life core reactor, other suitable sites in Alaska could also be identified, and some of those could be sites of mining operations that are often isolated and require a reliable supply of electrical power.

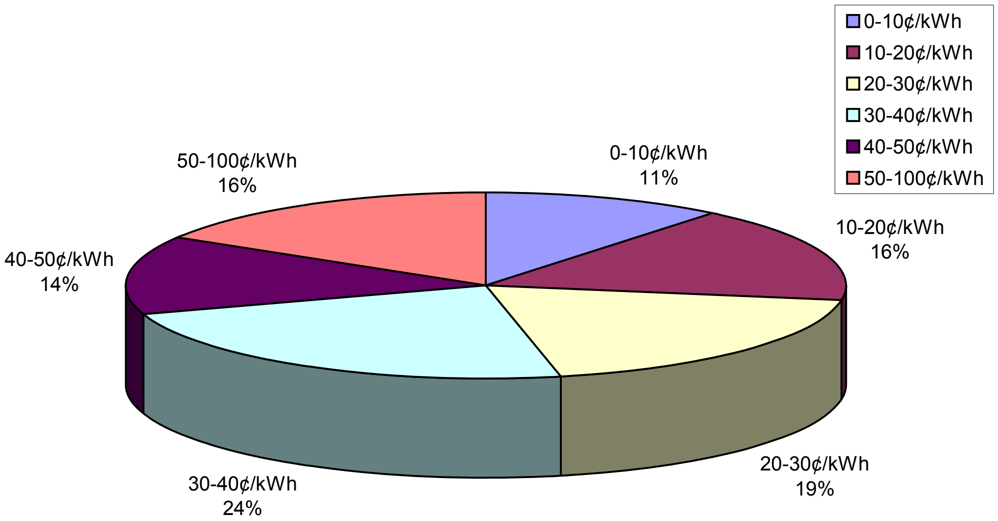

FIG. XI–4. Electricity costs in Alaska (74 utilities: state owned, publicly owned and cooperative), 2000.

XI–5.2. Hawaii

Hawaii uses oil to generate 78% of the state's electricity, compared to just 3% nationwide in the USA. Coal is used to generate almost 15% of the electricity in Hawaii. Much of that comes from the 180 MW(e) AES Hawaii plant located in Campbell industrial park. Its high technology design and excellent operation reduce hazardous emissions typically associated with burning coal, but it still creates carbon dioxide, a main component of greenhouse gases.

Hawaii does not use natural gas to generate electricity because transporting natural gas to Hawaii on a large scale is not cost effective. The gas that is sold in Hawaii for cooking is refined from crude oil after it arrives. Very little hydroelectric capacity exists (0.7%) because of the small and erratic stream flow and the limited number of possible dam sites.

Renewable energy from wind, solar and geothermal sources is a real area of opportunity for Hawaii. Hawaii obtains 6.5% of its electricity from renewables. Statistically, that puts them ahead of the mainland, which uses 2% renewable energy overall. Proponents of renewable sources say Hawaii's combination of heavy dependence on oil, high electricity costs and the abundance of resources makes it quite natural to push ahead in the direction of renewables.

Hawaii has no nuclear power plants because:

- The large size typical of nuclear power plants currently available from developed countries does not meet Hawaii's requirements;
- The State Constitution of Hawaii prohibits nuclear power.

In Oahu, the Hawaiian electrical company expects electricity demand to increase by 20 MW(e)/a. However, at the same time, all Hawaiian electrical companies have pursued demand side management — assisting customers to use less electricity and rewarding them for that financially.

Table XI–3 shows the average residential rates for electricity offered by the Hawaiian utilities (HECO, MECO and HELCO) in 2000 [XI–6].

TABLE XI–3. AVERAGE RESIDENTIAL ELECTRICITY RATES [XI–6]

Electric company	Average rate ($/kW·h)
HECO	0.1489
MECO	0.1853
HELCO	0.2214

From the electricity cost viewpoint, there could be a large market for small reactors in Hawaii. As the first site to install a small reactor, Maui Island may be the logical choice because its total requirement for electricity is not large, and the island also requires more fresh water. If small reactors are to be installed in the state of Hawaii in the future, the present state constitution that prohibits nuclear power would have to be revised.

XI–5.3. Mexico

XI–5.3.1. Electricity demand characterization

Demand for electricity in Mexico has increased steadily over the past decade. The demand was forecast to grow at a rate of 5.6% between 2003 and 2012 [XI–7]. The regions expected to see the largest increase are the north-east, and the Baja California and Yucatan peninsulas, primarily due to industrial development and the growth in tourism. According to Government estimates, the country will require $50 billion in investment over the next decade to meet the country's growing electricity demand.

The Comisión Federal de Electricidad (CFE) and Luz y Fuerza Centro (LFC) are Mexico's two State owned electricity companies. The CFE continues to dominate the electrical power sector, although the country's public electricity service Act was amended in December 1992, allowing private participation in generation activities, such as independent power producers (IPPs), self-suppliers, cogeneration and small scale generation. The CFE is obliged to supply electricity to the entire country as a public service, except to Mexico City and some municipalities of the states of Mexico, Morelos, Hidalgo and Puebla, where the LFC is the supplier. In 2002, the CFE and LFC accounted for 85.2% of Mexico's electricity generation capacity, of which the LFC contributed 2%. The Pemex Company accounted for 5%, IPPs for 6% and self-suppliers for the remainder. The CFE and LFC also control transmission and distribution of electricity [XI–8]. Figure XI–5 shows the distribution of unit capacity for the units owned by the CFE in Mexico. Figure XI–6 consists of a map with sites of the existing power plants and plant capacity in Mexico.

Mexico has a national interconnected power grid with four regional divisions: Northern, North Baja, South Baja and Southern (the largest). In the south-east, including the Yucatan peninsula and north-east, the grids are stretched, such that new generation cannot be added without bolstering the transmission network. Accordingly, the CFE has undertaken projects designed to make required improvements to the national grid by working with private companies to install hundreds of miles of new high voltage transmission lines over the next few years. Mexico has about 23 500 miles of transmission lines and about 400 000 miles of subtransmission and distribution lines.

XI–5.3.2. Possibilities for small and medium sized reactor deployment

The required electricity in the north-eastern region can be supplied by a fossil power plant, as a coal mining enterprise is located nearby, or by a nuclear power plant of medium or large size. Small reactors could be installed on the two peninsulas where:

- There are no big cities with large electricity consumption;
- The transport costs of oil, coal and gas are high;
- Small nuclear power plants could replace the existing non-nuclear small power plants;
- The electrical grids available are small.

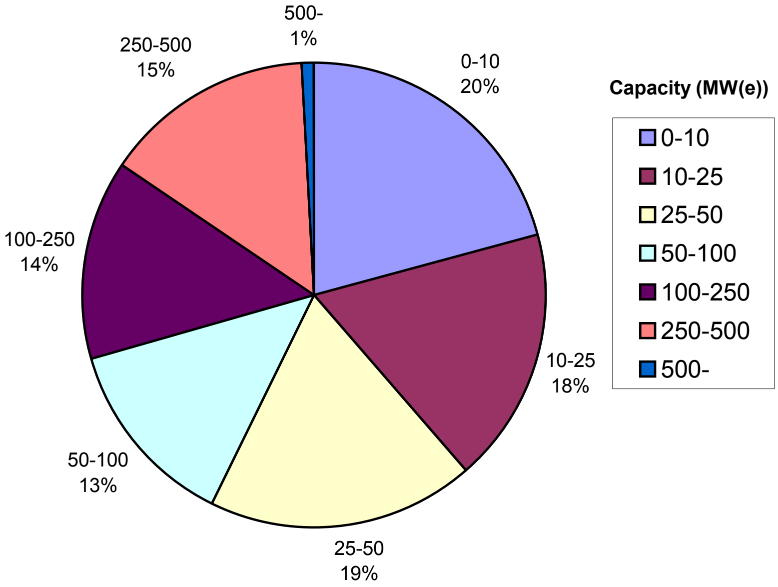

FIG. XI–5. Distribution of unit capacity of the Federal Electricity Commission in Mexico (total capacity = 32 208 MW(e), total number of units = 248).

FIG. XI–6. Map of power plants/plant capacity in Mexico.

To estimate possible small reactor deployment on the two peninsulas (Baja California and Yucatan), the following was assumed:

- Small reactors will be deployed from 2013 to 2020.
- Two cases of a growth rate for electricity consumption from 2003 to 2020 were considered: (i) 5.6% from 2003 to 2020 (constant); and (ii) 5.6% from 2003 to 2012 and 4.0% from 2013 to 2020.
- The share of the overall capacity for a small reactor was assumed to be (i) 60%, (ii) 40% and (iii) 20%.

The installed capacities of the Baja and Yucatan peninsulas were taken as 2716 MW(e) (2002) and 1800 MW(e) (2002), respectively.

Figure XI–7 shows the total required capacity on the two peninsulas of Baja California and Yucatan from 2003 to 2020. Figure XI–8 shows the required number of units of small reactors for the cases of a small reactor share equal to 60, 40 and 20%.

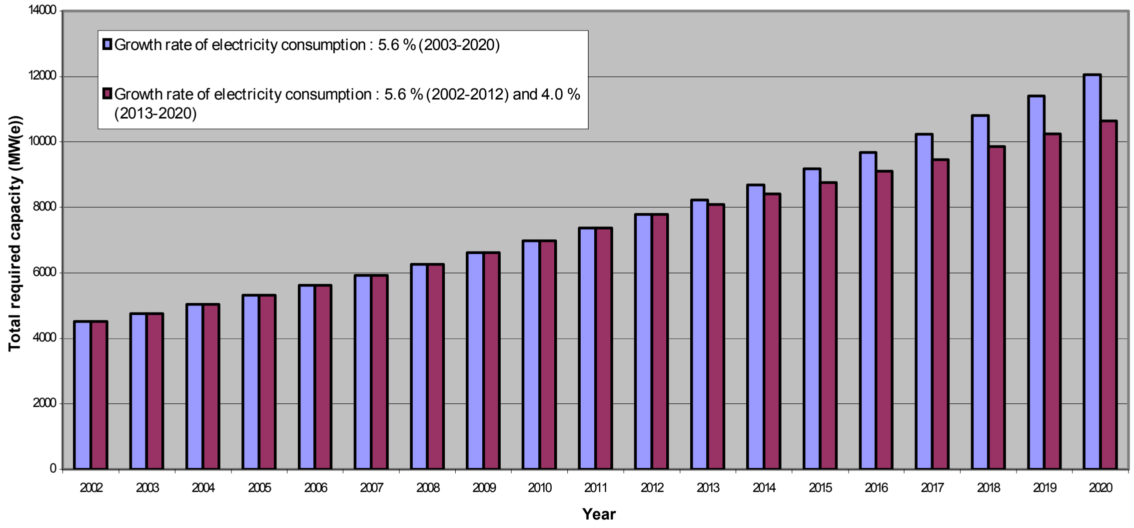

FIG. XI–7. Total capacity required from 2003 to 2020 on the two peninsulas of Mexico.

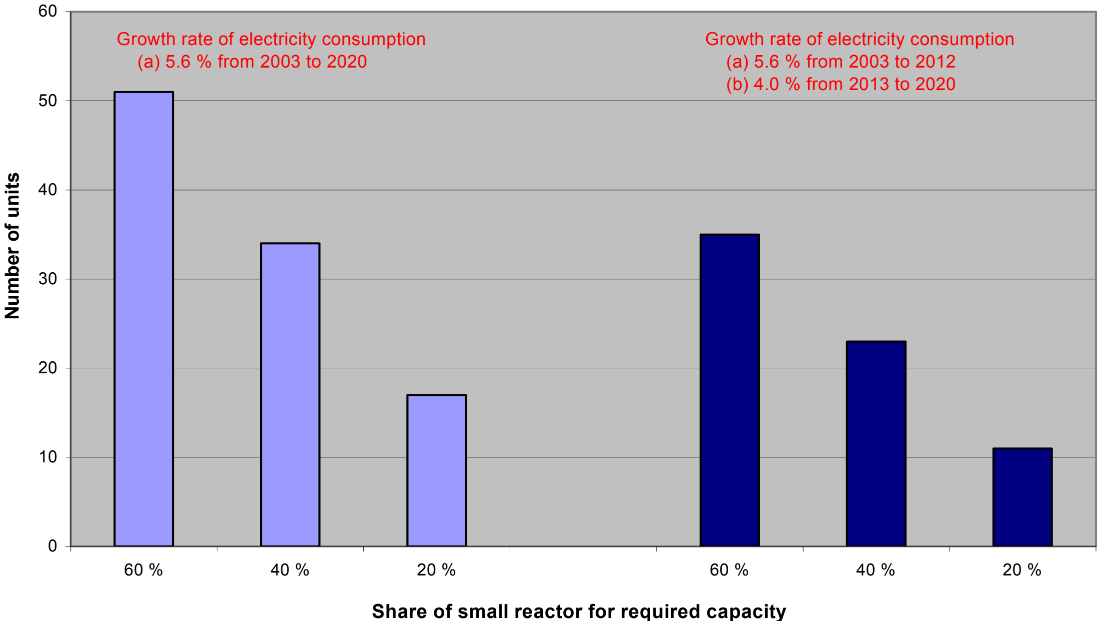

FIG. XI–8. Estimated numbers of units of small reactors for the three shares of small reactors in the overall energy production.

XI–6. SMALL REACTOR COSTS

The cost analysis completed in a previous study [XI–1] is currently being updated; therefore, recent preliminary evaluations were considered in judging the potential for small reactor deployment in the selected regions or countries. Figure XI–9 summarizes the preliminary evaluations in terms of energy and capital cost. As it is envisioned that small reactors would eventually be produced in series, comprising thousands of units, the cost estimates for such reactors, as carried out before the production stage, are highly uncertain. The basis for estimating the costs relies on both the experience with construction and operation of large water cooled reactors and other major power generation systems, and the perceived benefits from factory assembly and rapid installation of many standardized and serially produced units. Therefore, the previous study [XI–1] and the preliminary results of a recent study include a parametric evaluation of costs for the various cost assumptions. Reference [XI–9] uses as a reference and a starting point cost details taken from the cost evaluation performed in Ref. [XI–10] for an advanced liquid metal cooled small reactor of 4S type. In addition to this, conventional cost scaling factors are employed.

Figure XI–9 shows evaluation results for a sequence of the performed parametric evaluations. When all envisioned benefits of small reactor production and installation are realized, the generation costs are estimated to be between \$50/MW·h and \$60/MW·h. The difference is small and is unlikely to affect market selection. Small reactors may still be viable in many regions at these higher power generation costs. If the estimated costs are realized, this would make small nuclear power plants costs competitive in most of the evaluated developing countries.

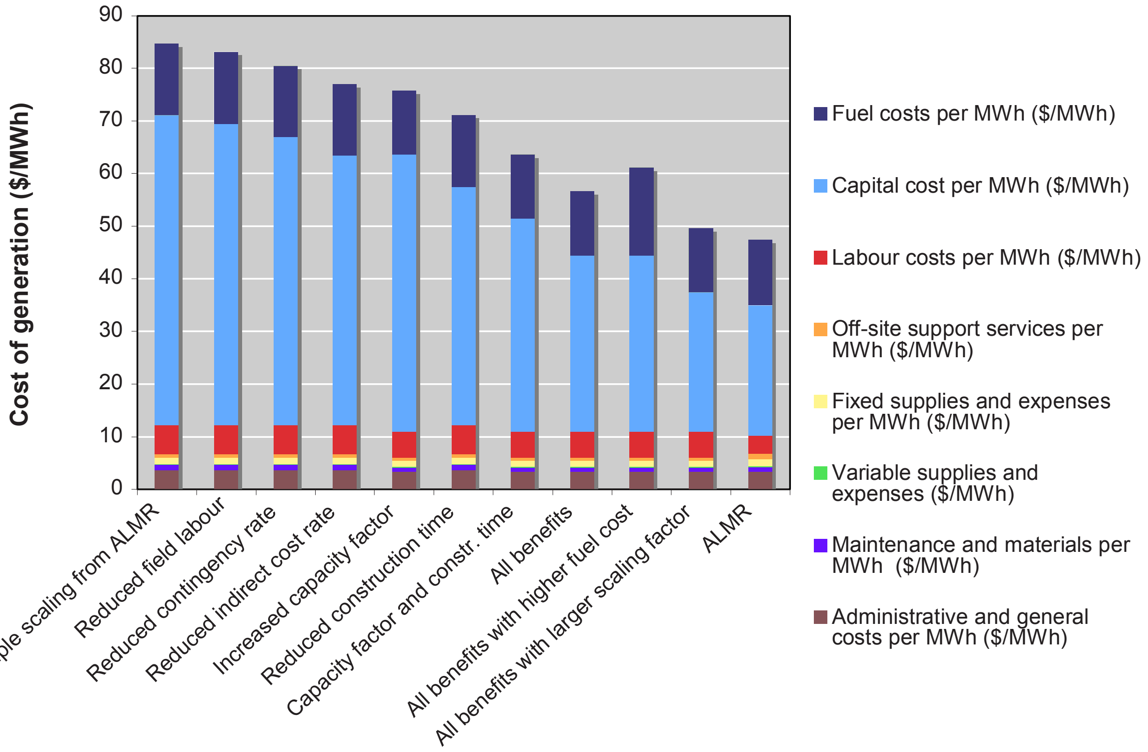

FIG. XI–9. Evaluated generation cost for commercialized small liquid metal cooled reactors as a function of the indicated assumptions. ALMR: advanced liquid metal cooled reactor [XI–9].

XI–7. EXAMPLE OF COST REDUCTION BY STANDARDIZATION AND MASS PRODUCTION

Considered in terms of conventional economies of scale, the construction costs for the unit of a small reactor of 50 MW(e) would be about three times higher compared to those of a large reactor of 1200 MW(e). However, the number of components and the amount of material and labour required to produce them could be substantially reduced in a small reactor via broad incorporation of the inherent and passive safety features and passive safety systems.

With design simplification factors taken into account, some forecasts indicate the costs of materials could be equal to, or less than, those of the materials used in a large reactor, when evaluated per unit of the output (MW(e)) [XI–11, XI–12].

Figure XI–10 presents the estimated evolution of costs of the 4S small sodium cooled reactor of 50 MW(e) [XI–9, XI–12] from the first of a kind (FOAK) plant to the *N*th plant in a series. The costs were estimated for the 4S design of 50 MW(e) with a 10 year cycle of operation without on-site refuelling (1990 design version). There is a little doubt that the benefits of the standardization, as shown in Fig. XI–10, would take effect if single orders for many units are received repeatedly. In Fig. XI–10, mass production is assumed to be ten units per year over 10 years. The total number of units is then 100 per 10 years.

In Fig. XI–10, the reduction of costs from the FOAK to the *N*th plant by 77% includes the effects of critical and irradiation tests, prototype tests, development of structural standards and licensing costs. All those would be required for the FOAK plant, but would not be needed for the serial *N*th plant. Of the total 77% reduction, learning achieved in serial factory based production is projected to yield a 61% cost reduction on transition from the FOAK to the *N*th plant.

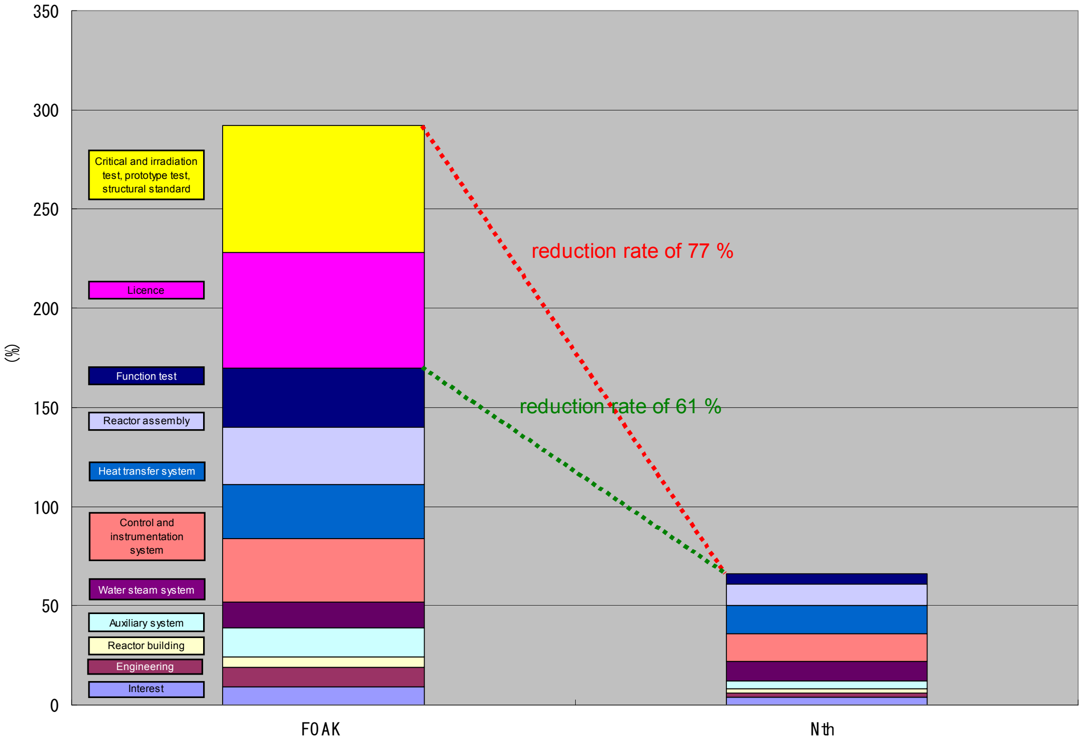

FIG. XI–10. Estimated construction cost of the 4S sodium cooled small reactor of 50 MW(e) for the first of a kind (FOAK) and serial (Nth) unit.

XI–8. CONCLUSION

The performed study indicates that there is a real near term market for small nuclear reactors, the market in which the electricity generation costs are high and there is no possibility to accommodate large power plants. This market appears small; however, after deployment of small reactors in the selected countries or regions, other potential sites could demonstrate interest in small reactors, if positive operation experience with the initial units were provided.

A candidate country or region could be selected for a more detailed study to be carried out in cooperation with the electrical utilities and the government. It makes sense to carry out such a study after the approval of a standard design is obtained from a national regulatory authority, such as the US Nuclear Regulatory Commission. If the detailed market study indicated that units with several power levels were required, then the project schedule could be adjusted to allocate time to obtain standard design approvals for the design with the different power levels necessary to meet market requirements.

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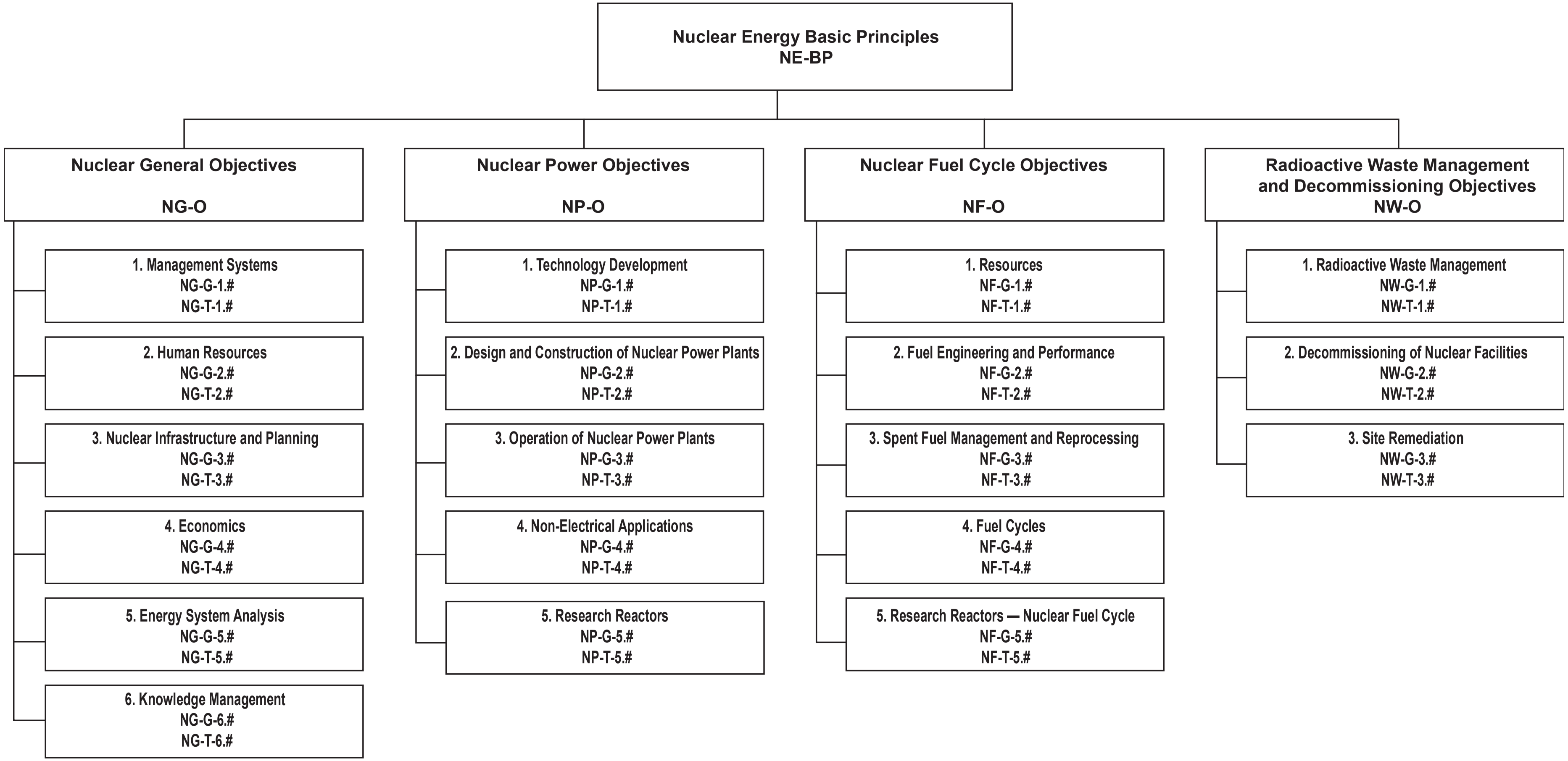

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