FOREWORD

This report was created by P. Florido (Argentina) within INPRO, based on a special service agreement with the IAEA. It is one of the chapters of a document called INPRO manual and deals with the INPRO area of economics. The report was reviewed regarding the technical content by C. Allan (Canada) and F. Depisch (Germany) taking into account the results of a consultancy held at the IAEA in July 2005 with participation of M.G. Andhansare (India), M. Castinieira (Spain) and V. Usanov (Russian Federation) and integrating the comments received from the Planning and Economics Studies section (PESS) of the IAEA.

It is important to note that:

1) This is a first draft of the Manual on Economics and it is still at an early stage of development. But the draft had been reviewed at a consultancy and the consultants thought that the information presented in the draft would be of interest and assistance to MSs performing INPRO assessments as part of Phase 1B (part 2). Hence it is being issued as a working paper for use by MSs performing such assessments. Because it is at an early stage of preparation it cannot be referenced.

2) The draft section on economics has been written to be as stand-alone as possible and it is recognized that when the complete manual is being finalized some of the information in the draft section dealing with economics may be re-located to another section in the integrated manual.

3) Feedback on the clarity and content of the draft economics manual from MSs carrying out assessments is welcome and is expected. As well, feedback/information from the assessments carried out by MSs will be used to update the economics section (and other sections) of the manual, for example, to provide additional examples of economic indicators and examples of results obtained from economic assessments.

4) Other draft sections of the manual, e.g. dealing with safety, waste management, etc., will be issued as working papers when it is judged that they are sufficiently developed to be of assistance to MSs carrying out INPRO assessments in Phase 1B (part 2).
# Table of contents

## CHAPTER 1. INTRODUCTION

## CHAPTER 2. BOUNDARY CONDITIONS FOR AN INPRO ECONOMIC ASSESSMENT

2.1 Scenarios for Energy-Electricity Supply
2.1.1 Selection of energy options
2.1.2 Methods to create an energy scenario
2.2 Parameters of an INS needed for an economic assessment
2.3 Determination of costs
2.3.1 Types of costs
2.3.2 Time base of INPRO economic assessment
2.3.3 Additional factors to be considered
2.4 Discount and financial rates
2.4.1 Cost of capital
2.4.2 Source of capital
2.4.3 Financial figures of merit
2.5 Economics and the cycle of development

## CHAPTER 3. BACKGROUND OF INPRO ECONOMIC REQUIREMENTS

3.1 Introduction
3.2 Economic Basic Principle
3.3 Economic User Requirement UR1.1
3.4. Indicators and Acceptance Limits of UR1.1
3.5 Economic User Requirement UR1.2
3.6. Indicators and Acceptance Limits of UR1.2
3.7 Economic User Requirement UR1.3
3.8. Indicators and Acceptance Limits of UR1.3 ............................................................. 39
3.9 Economic User Requirement UR1.4 ........................................................................... 45
3.10 Indicators and Acceptance Limits of UR1.4 ............................................................ 45

CHAPTER 4 REFERENCES ................................................................................ 48

ANNEX A: NUMERICAL EXAMPLE ........................................................................ 51

CHAPTER A.1 CASE DESCRIPTION ......................................................................... 51
A.1.1 Data used: ........................................................................................................... 51

CHAPTER A.2. ASSESSMENT STEPS .................................................................. 52
A.2.1. Electricity Scenarios .......................................................................................... 52
A.2.2. Energy Options Alternatives ............................................................................ 54
A.2.3 Technical assumptions. ...................................................................................... 55
A.2.4 Economic assumptions ...................................................................................... 64
A.2.5 Cost coverage and costing basis ......................................................................... 65
A.2.6 Discount and Financial Rates. ........................................................................... 72

CHAPTER A.3. INPRO INDICATORS .................................................................. 74
A. 3.1. Indicators of UR1.1........................................................................................... 74
A.3.2. Indicators of UR1.2........................................................................................... 80
A.3.3. Indicators of UR1.3........................................................................................... 83
A.3.3. Indicators of UR1.4........................................................................................... 84

CHAPTER A.4. INPRO ACCEPTANCE LIMITS................................................ 88
A.4.1. Acceptance Limit of UR1.1................................................................. 88
A.4.2. Acceptance Limit of UR1.2................................................................. 88
A.4.3 Acceptance limit of UR1.3............................................................................... 89
A.4.4. Acceptance limit of UR1.4............................................................................... 89
CHAPTER A.5.  CONCLUSIONS ................................................................................. 90

CHAPTER A.6.  REFERENCES .................................................................................. 95

ANNEX B: GENERATION COST METHODOLOGY ................................................. 97

CHAPTER B.1 POWER GENERATION COST METHODS ...................................... 97

B.1.1 Time factor and the discount rate ................................................................. 98

B.1.2 Levelized electricity generation cost ............................................................. 99

B.1.3. Net Present Value and Internal Return Rate .............................................. 101

CHAPTER B.2. SIMPLIFIED EQUATION FOR LEVELIZED COSTS .................... 104

B.2.1. Amortization Costs ...................................................................................... 105

B.2.2. O&M Cost .................................................................................................... 106

B.2.3. Fuel Costs ..................................................................................................... 106

B.2.4. Total levelized unit energy costs ................................................................. 108

CHAPTER B.3 SIMPLIFIED FORMULAS TO CALCULATE IDC ......................... 110

B.3.1. Mean Investment Time ............................................................................... 110

B.3.2. Constant Cash Flow .................................................................................... 110

B.3.3 Effective investment time ............................................................................. 111

B.3.4. First moment effective investment time ...................................................... 111

B.3.5. Comparison of approximate solutions for IDC ........................................... 111

CHAPTER B.4  PERTURBED VALUES AND ROBUSTNESS INDEX. ............... 115

CHAPTER B.5.  SIMPLIFIED LEVELED FUEL COSTS: ...................................... 118

B.5.1. Nuclear Fuel Costs: .................................................................................... 118

B.5.2. Fossil Fuel Costs: ......................................................................................... 120

CHAPTER B.6.  REFERENCES .............................................................................. 122
Chapter 1.
INTRODUCTION

The goal of the INPRO Manual is to enable the applicant of the INPRO methodology, called the assessor, to perform a quantitative assessment of an Innovative Nuclear Energy System (INS) based on the INPRO Methodology, described in Ref. [1]. The main step of the assessment method (Chapter 3 of Ref. [1]) consists of determining the value of the INPRO Indicators for a given Criterion, and comparing these values with the corresponding INPRO Acceptance Limits of the Criterion. Thereafter, the judgment on the potential, i.e. the capability, of the INS is to be performed for each Criterion, then the uncertainty of the judgment (based on the maturity of the INS) and finally an aggregation of the judgments. Additionally, considerations for necessary or desirable RD&D are possible.

The present work gives a detailed description of the procedure needed to determine the value of all INPRO Indicators in the area of Economics, including its Acceptance Limits. This document follows the guidelines of the INPRO report “Methodology for the assessment of innovative nuclear reactors and fuel cycles, Report of Phase 1B (first part) of the International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO)”, IAEA TECDOC-1434 (2004), Ref. [1], together with its previous report “Guidance of the evaluation for innovative nuclear reactors and fuel cycles. Report of Phase 1A of the International Project on Innovative Nuclear Reactors and Fuel Cycles (INPRO), IAEA TECDOC-1362 (2003), Ref. [26].

Background information is provided that is needed to perform the economic assessment (e.g. definition of the energy demand scenario, options for energy supply, etc.) and the tools that an INPRO assessor could use to perform the assessment are described, in a general way, in Chapter 2.

In each area of interest – Economics, Safety, Waste Management, etc. - a set of Basic Principles, User Requirements, and Criteria, consisting of an Indicator and an Acceptance Limit, have been specified. The Basic Principle, User Requirements and Criteria for Economics are set out in Table 1.1. The Indicators are stated in rather general terms such as “cost of energy from alternative sources” or “financial figures of merit”. Therefore, in chapters 3 of the document guidance is provided on the selection of specific Indicators and on the choice of Acceptance Limits for each Criterion. It is recognized that a given Member State may choose other specific criteria so the information presented in chapter 3 should be considered to be guidance.

To assist the reader, a detailed hypothetical example of an assessment in the area of economics is presented in Annex A. References are provided for the data used to calculate the values of INPRO Indicators in the hypothetical example and the rationales for the Acceptance Limits are discussed.

Annex B includes a detailed description of a set of formulas that could be used in order to perform a detailed or simplified INPRO economic calculation, without using complex computer codes. All the formulas include a description about how they have been derived.
from basic economic concepts, and references are provided to relevant economic and nuclear engineering literature texts.
**Table 1.1 Basic Principle, User Requirements and Criteria in Economics [1]**

**Economic Basic Principle BP1: Energy and related products and services from Innovative Nuclear Energy Systems shall be affordable and available.**

<table>
<thead>
<tr>
<th>User Requirements</th>
<th>Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Indicators</td>
</tr>
<tr>
<td><strong>UR1.1</strong> The cost of energy from innovative nuclear energy systems, taking all relevant costs and credits into account, $C_N$, should be competitive with that of alternative energy sources, $C_A$, that are available for a given application in the same time frame and geographic region.</td>
<td>1.1.1 Cost of nuclear energy, $C_N$.</td>
</tr>
<tr>
<td></td>
<td>1.1.2 Cost of energy from alternative source, $C_A$.</td>
</tr>
<tr>
<td><strong>UR1.2</strong> The total investment required to design, construct, and commission innovative nuclear energy systems, including interest during construction, should be such that the necessary investment funds can be raised.</td>
<td>1.2.1 Financial figures of merit.</td>
</tr>
<tr>
<td></td>
<td>1.2.2 Total investment.</td>
</tr>
<tr>
<td><strong>UR1.3</strong> The risk of investment in innovative nuclear energy systems should be acceptable to investors taking into account the risk of investment in other energy projects.</td>
<td>1.3.1 Licensing status.</td>
</tr>
<tr>
<td></td>
<td>1.3.2 Project construction and commissioning times.</td>
</tr>
<tr>
<td></td>
<td>1.3.3 Relevant indicators of the political environment show long-term support for nuclear power.</td>
</tr>
<tr>
<td><strong>UR1.4</strong> Innovative energy systems should be compatible with meeting the requirements of different markets.</td>
<td>1.4.1 Flexibility (Robustness) of INS.</td>
</tr>
</tbody>
</table>
CHAPTER 2.
BOUNDARY CONDITIONS FOR AN INPRO ECONOMIC ASSESSMENT

Very different assessors could perform an INPRO economics assessment from national decision makers up to academic institutions, so the overall framework of an assessment could change from a country specific situation up to a global scenario (see section 3.1 in Ref. [1]). But the steps required for an economic assessment are common for all assessors applying the INPRO methodology.

Differences in assessment results could be caused by different methods, codes and assumptions that the assessor used. Therefore, clear definitions must be provided for economic indicators and acceptance limits so that differences in assessment results are not caused by confusion about terminology and formulae but can be explained by differences in scenarios.

A detailed description of the necessary economic boundary conditions of scenarios will be presented in this chapter, together with information about the different tools and methods that could be used to perform an economic assessment using the INPRO methodology.

2.1 Scenarios for Energy-Electricity Supply

As set out in Section 3.1 of Ref. [1], the starting point for an INPRO assessment is the determination of energy scenarios that set out the growth in energy demand as a function of time, the available energy supply options including the role of an INS in meeting this energy demand. In some scenarios an INS may include NPPs to be used for a variety of applications, for example, electricity production, hydrogen production [2], and desalination. For simplicity this chapter of the manual is presently focused on electricity generation.

2.1.1 Selection of energy options

In the area of economics, the energy scenarios need to be developed taking into account different aspects that define very precisely the relevant data needed for an INPRO assessment. In the following some aspects are discussed in more detail that influence the selection of an energy option.

1. Investment rules for new installations related to power supply: Different criteria can be used in the economic decision making process, particularly how to decide among different options for electricity production. The criteria used will determine how much decision makers are willing to pay to use nuclear energy. Very different situations could occur, such as a country in which the investment decisions need to be based on purely commercial rules in a completely deregulated market, up to countries with a centralized (government) decision making process in which the investment is decided by other investment models. For example, for some assessors, using the INPRO methodology, the
Business As Usual (BAU) approach could be the economic criterion, and then only the cheapest solution will be a credible, useful option for deployment. Another example could be an assessor interested in the deployment of nuclear plants for strategic reasons (energy security for example), so he is willing to accept additional costs of nuclear power up to some level compared with other electricity alternatives. Different scenarios could be evaluated with different classical investment figures of merits.

2. Limitations on the size of plants to be deployed: There are needs and related challenges of meeting the expansion rate of power supply specified in a scenario. It is necessary to take into account limits, e.g., technical limits of the energy options that could potentially introduce constraints on the size of plants to be deployed. A scenario could be based on additional power supply to a well-developed and large interconnected grid in which there are no technical limits on the size of the units to be deployed. A very different situation could be the case of a localized small grid for which a bottleneck could be the requirement to produce electricity by power plants with very small output.

Different energy technologies have different characteristics. For example, gas turbines are available from 1 MWe up to 280 of MWe, but combined cycle single units start at 20 MWe and range up to 400 MWe. Piston engines generators start at 100 KW for base load generation, but are very unusual for loads more than 20 MWe. Many other technical limits could define boundary conditions that could preclude specific energy options (land use per megawatt, time between maintenance, etc.). To avoid inconsistency, the technical limits of each potential power technology need to be checked for compatibility with the electricity scenario. Such characteristics also need to be taken into account when optimizing the energy supply mix.

3. Load type: For electricity generation two types of load changes can be distinguished: first, changes that occur over a rather long time period, such as hours of the day (morning, evening), days of the week (work day, week end) and seasons for the year, and, second, momentary surges that require very rapid changes in the generating capacity of the system. In a given grid a pattern is normally established for electrical service demands, which depends on household habits and on commercial and industrial schedules. Variations in this pattern are generally predictable. However, weather and other climatic conditions can have a marked effect on the load requirements. Such changes are somewhat predictable on an average basis from weather regions. To define the power technology options, the assessor needs to define the type (or types) of load demand, which he needs, because some types of electricity technologies are better matched to different load requirements. For example, in some MSs nuclear plants are used primarily to meet base load demand and other technologies are used for power peaking. In other MSs where nuclear plants dominate the installed capacity, the load factor for (at least) some of the nuclear plants would be considerably smaller than for plants operated to meet exclusively base load demand and the value of economic indicators in such a situation would/could be significantly different.

4. Fuel availability: The availability of fuel has a direct impact on the different electricity alternatives considered. Usually a given power technology uses a specific type of fuel (Only, a limited number of technologies could use different fuels). Taking into account
the availability of different fuels is thus, useful in determining whether or not to include a given power technology as an energy option in the scenario.

5. National energy strategy: Additional boundaries conditions for scenarios are given by values, prices and limitations on the availability of competing products and raw materials for other nuclear and non nuclear energy options. The boundary conditions also include the industrial status of the country or region under study, such as the capacity to supply specific components, systems, and materials (such as nuclear fuel, heavy water, etc.), project management experience, and the strategy adopted regarding importing or supplying domestically specific components, systems and materials.

Political strategies, e.g., polices that favor renewable energy sources, efficiency and recycling, and environmental agenda could recommend specific technologies to be included in the study. Such political considerations could reflect strictly local policies. Some countries may include mandatory recycling within their legal framework, or specify emission limits, which might in the end exclude some generation technologies, but a technology should never be excluded, a priori, without a proper justification. Nowadays there is a tendency towards international treaties, which could favor some options to be included or excluded in an electricity generation system.

### 2.1.2 Methods to create an energy scenario

An INPRO economic assessment could be performed by academic institutions, agencies, or even by private companies or nuclear designers, interested in no specific energy grid. As an example, an assessor using the INPRO methodology could be a reactor designer trying to evaluate a given reactor concept targeted to compete with piston machines in remote areas, without any specific siting selected. Another assessor could be an international agency trying to evaluate the future advantages and disadvantages of different options, like the scope of the well known OECD [11] or UNIPEDE studies [12], using data of plants already in operation or based on real projects. An inherent limit of this approach applied within the INPRO methodology might be that INPRO is focused on innovative systems and therefore necessarily includes future trends and forecasts. It can therefore probably not be excluded that a biased selection of possible alternatives will produce biased results, especially when the assessor is comparing innovative systems far away from the present situation.

In general, the scenario involves a grid with different energy sources already used for power generation. To combine existing energy systems with options relevant for the assessor is a simple method for selecting the energy alternatives. The assessor will have the possibility to add new (not yet present in the system) energy sources because past energy options are not necessary the unique options that will be deployed in the future.

To create such a scenario that takes into account all aspects discussed above, different methods could be used as follows:

1. Use of a reference scenario: In very well known nuclear initiatives [6], different scenarios and assumptions about the nuclear competitors have been taken from referenced studies in order to calculate a competitive target for innovate nuclear plants. A number of
studies dealing with the economics of future electricity supply have been published (refs.[7][8][9]). If published scenarios are useful for an assessor using the INPRO methodology, the reference values (usually time dependant), and detailed specific nuclear system costs, could be used to produce the data that are needed for the economic assessment. This is a typical approach used by designers and vendors because they are fully informed about the technical details of their nuclear power products, and they prefer to use data about competitive products taken from references. This approach could be easily used to compute INPRO indicators and is consistent with the reference values if the deployment rate of the reactor type could be taken as a perturbation of the reference nuclear scenario (in case it is reduced to some specific region, or for a shorter time frame, for example).

2. Full scope simulation: Starting to create a scenario for a given reference time (e.g., 20 years into the future) in a given economic framework (population and total energy growth for example), economic, time trend or simulation codes could be used that are well known. General codes like IIASA MESSAGE [3], MAED [10] (code for load structure) or very grid detailed codes like WASP [4] (code for energy allocation) could be used for modeling the evolution of the demand for domestic use, industrial use, thermal heat, etc. They simulate the impact of different policies and could translate local and global policies into quantitative electricity targets. MESSAGE [3] is a code that could be effectively applied for global or interregional modeling. Combinations of several types of codes could be performed to proceed from very generic scenarios to quantitative time dependant values of nuclear electricity expansion. With this type of modeling the future range of the size of the load structure could be predicted, mainly peak and base load demand. This could be relevant particularly for some assessors using the INPRO methodology, from experts interested in the global energy future to governments interested in solving the energy need of a remote location with an autonomous power source.

The result of such type of modeling is, however, limited: Undoubtedly, a lot of information could be extracted from the code results, but to be fully usable, some codes require hundreds of detailed input data, especially economic figures of merit of each power option, in order to be able to simulate expansion options (like WASP Code for optimal expansion). The calculated time trends (electricity expansion, generation alternatives) can produce very detailed requirements for and timing of new plants under different scenarios (e.g., SRES Scenarios [5][26]), but the calculations are fully dependent on many input values used to describe the different energy options and finally the accuracy of the results depends on the accuracy of the input data and assumptions.

Thus, in using such codes it is important that the INPRO assessor is knowledgeable about the specific models and assumptions used in the codes. In some cases, the best approach could be for an INPRO assessor to work jointly with a code expert and so take advantage of the expert’s knowledge of the code to adapt it and use it to its fullest capability to meet the requirements of an INPRO economic assessment. The Planning and Economics Studies Section (PESS), Department of Nuclear Energy, IAEA, is experienced in providing assistance to MSs with energy planning and so can assist with defining the scenario for an INPRO assessment and in providing generic information for use in economic analyses [25] [30].
3. Customized oriented approach: If the scenario (in which a given assessor is interested in) is not comparable with those in published reports, and full scope simulation is not a realistic option, another option is to represent the scenario using a limited number of parameters and simple models. Computers codes such as the DESAE code [31] may be useful. Even simpler numerical models could be developed using spreadsheets and a combination of data from published reports. Expansions rates of other energy alternatives in the international market could be taken from published reports, for example to calculate the boundary conditions for international commodity prices.

In due course, it is expected that a standardized toolbox of codes applicable to INPRO economic assessments might become available.

It is important to stress that this manual deals only with economics and the INPRO economic criteria. Thus an energy option that might ultimately be excluded for some other reason, such as safety, might still be evaluated for its potential to meet the INPRO economic criteria. Other INPRO areas will be dealt with in other chapters of the INPRO manual. Political decisions that directly force the application of some options, for example policies that force some energy (e.g. renewables) share of the power generation, can, at the moment, not be fully evaluated in the INPRO economic assessment because the assessment method has not been developed as a tool to calculate the economic impact of different policies.

2.2 Parameters of an INS needed for an economic assessment

Specific and detailed economic comparisons of near term deployment of a given NPP and alternatives in a given site or country have been extensively studied and published in the past. Such publications include IAEA guidelines [13], specific case studies in a country [14] or general studies in several countries as in the DECADES project [15], however these were not assessments applying the INPRO methodology [1]. INPRO assessments will be focused on the inclusion of innovative nuclear systems, addressing innovation in future scenarios (with a time horizon of up to 50 years and beyond), not only considering the present or near term situation.

In an INPRO assessment with innovative designs, all the technical data may not be available, to perform a full cost calculation, as can be done for reactors already in operation and other commercially mature components of an energy supply system, because in an INS some (or many) components may be at an early stage of development. For example, just to calculate the French PWR fuel cycle cost for comparative assessment using N4 fuel cycle data approximately 150 input data are required, without taking into account taxes [16].

Thus, a calculation of economic parameters of an INS may need to be done using a more simplified approach, based on fewer (but still up to 30 to 40) data for each power source [11][12], but the data used are to be consistent with the chosen energy scenarios and
alternatives. Experience shows that such simpler calculations for the nuclear fuel costs “are broadly consistent with those of more detailed analysis” [17].

For costs’ assessment, many different technical parameters need to be specified, to calculate a consistent set of indicators that are in agreement with the scenario and the electricity options. All these technical parameters could be summarized under the following main headings:

1. Complete description of Energy Supply System: The INPRO assessor needs to define the Innovative Nuclear Energy System (INS) that will be evaluated [1]. For INPRO, the term system includes “the complete spectrum of nuclear facilities”. To define the system, the assessor needs to specify the boundary limits that surround the facilities and steps included in the evaluation. All the facilities and steps (interdependencies between facilities) inside the system need to be explicitly calculated, and the other facilities and steps outside the system (outside the boundary limit) need to be taken into account by their cash flow through the boundary. For example in a system definition that does not include spent fuel management because the spent fuel is returned to the supplier, all the expenses of the back end costs need to be explicitly considered. For the same example, the assessor could be interested in buying the fuel elements from a supplier other than the fuel company of the reactor supplier, or he could be interested in making supply arrangements for each of the different stages of the front-end of the fuel cycle with different suppliers trying to reduce costs by increasing competition. To perform an economic assessment each step of the INS needs to be described by:

a. Defining the production unit,

b. Calculating the amount of production required,

c. Computing the price of each production unit

d. Specifying the time distribution of each payment.

e. Specifying the price evolution of production unit, if it is applicable.

The system will be completely described for the economic assessment, when all these data have been specified, for all the facilities (nuclear and non nuclear) needed for the economic evaluation.

2. Facilities Specifications: Each facility included in the INS definition need to be specified in two main categories:

a. Facility specification relevant for economic assessment: like output capacity, efficiencies and plant specifications. A NPP requires net electrical power, net efficiency, core power density (in KW/Heavy Metal load), time between refueling, fraction of core reload and burn up. An enrichment plant requires the output capacity, cascade efficiency and tail concentration.
b. Facilities performances: Load factor and plant life are required to perform an economic assessment. In evaluations of some plants an average but constant load factor during the total plant life could be used, while for another assessment the assessor could apply one load factor during the first years of commercial operations and a different one later in the plant life. This type of consideration will depend on assessor’s assumptions. Several nuclear power plant features might be modeled on a time dependant basis, such as changes in thermal efficiency to account for changes in fouling factors, clearances, etc. But, to be consistent, if such factors are taken into account for nuclear plants in a given assessment, similar ageing effects should be included for alternative energy sources, such as the decrease in the efficiency of gas turbines resulting from blade erosion, combustion chamber depositions and debris, etc.

In addition to technical parameters also economic parameters have to be considered:

1. Fiscal regimes: Fiscal regimes have a very significant impact on calculated generating cost of electricity and are very different from country to country, and national, regional and local conditions could vary substantially. As shown in Ref. [18], the introduction of some simulated harmonization of fiscal regimes has not been possible, so only a common very high-level fiscal regime policy could be considered. For example a special tax or insurance for a given technology, etc. The calculations of generating costs usually are carried out without income and profit taxes because such taxes do not affect the relative competitiveness [11] of different energy sources. On the other hand taxes on fuels, emissions and plant specific taxes that may differ from plant to plant, should be included in the cost if they are relevant for the assessor.

2. Constant monetary term: Cost elements used in calculation of generating costs will be expressed in constant monetary terms, as it is generally accepted that calculations performed in constant money are best suited for comparison. So no inflation correction need to be included in time dependant cash flows and variation in future prices of the components are considered as a drift in the constant money price.

3. Determination of generation costs: There is no unique and universal methodology to estimate generation costs, but in order to create a sound basis for comparing relative costs of alternative energy system technologies, an appropriate approach is to use Levelized Lifetime Costs (LLC) method (also called Levelized Unit Energy cost or LUEC) to compute all life cycle costs, as required by INPRO. This is a well-developed method for many applications and is explained in Annex B. For simplicity it could be a useful approximation to take the amortization time as the lifetime, in order to avoid the complexity associated with power upgrading and updating of a project fully amortized. Proper back fitting needs to be considered, especially for technologies with short duration between necessary major refurbishments, like gas turbines or wind turbine technologies.
2.3 Determination of costs

The approach used in INPRO requires the comparison between different alternatives for investment, so it is important to use cost data that are consistent for the different energy systems and for different options of the same energy system.

Problems with cost data consistency could be a central issue when the assessor is combining different types of technologies. One source of inconsistency could arise from comparing commercial facilities deployed 10 year ago with new facilities using projections of data for a long time period based on a paper analysis. The status of knowledge of both types of facilities could be so different, that even the best efforts will be probably biased in favor of one option or another. Another source of inconsistency could be produced when costs for different scopes of supply are classified under the same name. This type of wording mismatch could happen in the comparison of the direct cost of a nuclear reactor and a fossil plant. For example, if a nuclear reactor requires a cooling tower usually the cost will be included in the direct plant cost, but for some fossil plants (e.g., some combined cycle gas turbines contracts) the cooling tower could be included as an owner’s cost. A typical uncertainty of this cost coverage is what is really included as investment costs for one system compared with that for others.

These types of discrepancies are not technology specific. Some authors recommend that care be taken when fossil fuel alternatives are considered, particularly to be clear what is included in the cost of a turnkey technology [19]. For example, gas turbines fuelled with natural gas could require additional investment in gas pressure reduction systems, if they are supplied from a high-pressure pipeline, or natural gas compressors, if the turbine is supplied from a low-pressure pipeline. Gas turbines fuelled with liquefied natural gas require storage and transfer facilities. It needs to be ascertained whether such facilities are included in the fuel price or in the projected investment.

For comparison between different alternatives, the usual definition of direct cost could change because different energy technologies could have several ways to consider cost. For example in the investment some technology suppliers could include the condenser, but it may not be included in other published data.

Standardized accounting systems are available for nuclear power plants. The IAEA has developed a well known comprehensive accounting system capable of addressing a wide spectrum of costs [20]. Some countries use their own cost accounting system [21]. For INPRO only a very simple cost definition is required, so a very broad definition will be used trying to follow the suggestions for advanced plants [22].

2.3.1 Types of costs

For INPRO, cost needs to include:

1. Investment charges: Usually investment charges are divided in different categories:
a. Direct construction costs: These costs include the cost of the plant, materials and labor required for installation. These need to include land and land rights, structures and improvements, plant equipment including generator and electrical equipment like switch gear and transformers, and special materials (like moderator for a HWR or coolant inventory for a lead bismuth reactor for example).

b. Contingency allowances: For all the plant investment a contingency allowance should be made to provide for unforeseen or unpredictable costs. Often the designer can determine an appropriate allowance item by item or as a lump value for all the direct construction costs. Usually the contingency allowance depends on the maturity level of the design or gaps in engineering knowledge. It also depends on the source of cost estimation (based on ordered plant, paper analysis, quotation, feasibility study or previous experience [11]) or the degree of innovation (proven design, extrapolated design, or novel design [23]).

c. Indirect construction costs: A number of indirect construction costs must be added to the direct construction costs. These include the cost of contracting, design, engineering, inspection, start up, and interest during construction. Indirect cost also includes construction facilities, equipment and services. This account includes buildings and other facilities that are removed after construction has been completed. Indirect costs also include taxes and insurances, if they are applicable, in agreement with the discussion of Fiscal Regimes presented under the Section 2.4 Economic Assumptions above. Cost for staff training and for plant start up are considered indirect costs. Owner costs, including all the costs incurred by the owner in carrying out the project, like licensing costs, public relations and administrative overheads are in the category of indirect costs. Also the indirect construction costs often change very widely according to differences in accounting systems and to the experience of the contractor in building a specific plant. In this aspect it is very important to consider the scope of the assessor and the scenarios proposed, because if the assessor is interested only in nth of a kind power options, in his system definitions the cost for R&D and first of a kind cost are not included, but if the assessor is interested in considering all costs to deploy an INS, all the cost and learning needs to be included. Some differences between direct costs and indirect construction costs depend on the type of contract because in a fixed price “turnkey” contract many indirect costs are included in the fixed price. Thus, if they are added to the indirect costs although they have been included in the price of equipment supply, the assessor will be double counting those items.

d. Backfitting cost: This cost includes all the major refurbishment costs, not included in the annual O&M costs, required to keep the performance of the plant within the declared values, like steam generator replacement, or pressure tube replacement in pressure tube reactors. The total costs for backfitting is very important, together with the time when this capital expenditure is required, especially in levelized values.

e. Decommissioning cost: Costs of decommissioning, waste management and disposal are included in investment charges, together with the time when they are required.
Usually decommissioning and waste management costs could be applied in different stages and for different times, and therefore for the levelized values the time schedule is a major issue.

2. Fuel cycle costs: Fuel expenses are the second major component of nuclear power costs, and the most important cost for fossil fuel plants. If in the INS description the assessor proposes a system with fuel fabricated or negotiated in detail inside the system (and not bought as a single item at fixed price), the analysis becomes more complicated. For a detailed fuel cycle the analysis of expenses is complicated since a number of operations are involved and economic factors are sensitive to irradiation time in the reactor as well as to numerous financial and process variables.

a. Fuel element costs: In nuclear plants the classical fuel costs is expressed in $/Kg of heavy metal included in the fuel (uranium, plutonium or thorium), and the way to perform the assessment of such costs depends on the scope of the system. In a system including a single contract for the fuel supply during the whole plant life without any concern about external price evolution, resources depletion, etc, only the price of the final (fabricated) fuel elements and schedule for payment are needed. This approach could include or not the spent fuel management costs. In a detailed fuel cycle assessment, three main items are required:

i. The fuel costs included in the cost of the fuel elements, consisting of the costs of the original ore, enrichment and conversion steps for enriched uranium fuel.

ii. The costs of manufacturing the fuel elements and processing the irradiated material are of great importance. Since there is a minimum plant size required for economic operations of any technology, unit costs for a production volume smaller than the economic size will considerable increase the costs.

iii. Since the time required for the complete fuel cycle operation could be in the order of 2 to 6 years [16] significant costs may be involved because of the time value of money, which is sensitive to the discount rate used, and therefore these costs needs to be specifically addressed.

b. Fuel charges: Two types of charges are essential for any nuclear reactor operation. The first charge is the first core costs that is amortized over the plant life. This fuel needs to be supplied prior to plant start up. The costs could be high, particularly for low power density cores, high enrichment cores or long life cores. The second charge is the refueling charge, necessary to replace the losses of fissile material (e.g. uranium) by burn up due to the power generation between refueling. The first core implies a fuel demand bigger than any refueling demand during the plant life, and the payment needs to be done in advance to the commercial operation, so it is very relevant in LUEC, particularly at a high discount rate.

c. Spent fuel costs and credits: Two other costs are relevant for the fuel cycle. The spent fuel management cost and the related High Level Waste (HLW) management
costs need to be included. Another important cost is the credit for fissile content in spent fuel, particularly for reprocessing cycles, and represents a major difference with a Once Through (OT) fuel cycle.

3. Operation and Maintenance Costs: The operation and maintenance (O&M) expenses include the direct and indirect payroll, the cost of special materials, makeup (including D2O, special coolants, etc.) and general supplies. Miscellaneous operation and maintenance costs include items such as public relation, new staff training, rents and travel. It also includes liability insurance and the fixed charges for the working capital to pay for items in the O&M category. O&M in annual basis usually is divided in fixed O&M costs including those that do not depend on the energy generated each year, and variable O&M costs including those that depend on the energy generated. Usually variable O&M costs are considered proportional to the annual electricity output.

2.3.2 Time base of INPRO economic assessment

After fixing the time base for all the calculation of the INPRO economic assessment, all the costs, obtained from different sources need to be compared in constant money terms and expressed for a single time base. For this purpose appropriate currency deflators need to be used for price calculation of each element, because published price data are not usually expressed in constant money terms for the same date fixed by the assessor for its assessment. This is important when the results of the INPRO study are to be compared with others studies and with other (non nuclear) technologies inside the same INPRO assessment.

2.3.3 Additional factors to be considered

1. Currency exchange: The choice of a common currency unit is essential when different economic data sources are used, for different elements and systems in a given INS, and in other energy alternatives. As pointed out in several studies [11], exchange rates do not reflect purchasing power parities accurately and their use might affect cost comparisons between countries in a way that does not correspond to real costs differences. In particular the exchange rate between countries could fluctuate over time. Therefore the assessor should be extremely cautious in comparing cost data from different countries although they are expressed in a common monetary unit. Usually the use of constant prices properly accounts for most deviations. Sometimes, however, price differences arising from different purchasing powers or price differences for very specific products and services that do not follow the general rules of average economic variables can not be taken into account.

2. Price Setting: Usually the costs discussed in INPRO will refer to new power supplied to the station busbar, where electricity is fed to the grid. Thus, it excludes costs of the plant substations, transmission to the network and distribution to end-users. But for some energy scenarios (Section 2.1) and alternatives (Section 2.2) the cost to transport electricity could be included in the assessment in order to study the advantages and disadvantages (trade off) of small and medium sized, dispersed power systems compared
with large centralized plants. This is not in the usual economic assessment approach [11][12][17][18] but could be relevant for some assessors.

2.4 Discount and financial rates.

2.4.1 Cost of capital

As shown in many studies, results of an economic assessment and particularly the relative magnitude of differences between alternatives are highly sensitive to the discount rates used. The choice of a discount rate for decision making by a given assessor using the INPRO methodology will depend on its specific situation and the overall economic, regulatory and commercial framework of the country. Although there is extensive published literature on discount rates and their relationship with financial risk and required rates of return for private or public investor, there is no consensus view on the matter. (a few references to be included here)

The costs of capital for new generation capacity will likely be higher for plants in competitive markets than in traditional monopoly markets. Discount rates used for project evaluation will therefore be higher as well.

The costs of the construction of a standardized series of plants would be expected to lead to cost reductions as a result of learning. Learning will lead to savings in related areas, e.g., reductions in construction time and/or commissioning times. On the other hand, if there is a significant time span between projects, costs could increase as a result of so-called “knowledge depreciation” (Section 4.1.2 in Ref. [26]).

2.4.2 Source of capital

In most countries domestic savings are the main source of capital for infrastructure projects, including energy and electricity infrastructure. Availability of domestic capital will be most constrained in developing countries. Even where domestic savings comfortable exceed the energy sectors demand of capital, energy companies will still have to compete with other sectors for domestic financial resources. In addition, energy investment can occasional involve mega projects and in such a case the excess of domestic savings over energy investment requirements could be much smaller. Furthermore domestic savings need to be mobilized through financial markets.

The shortfall between investment requirements and domestic savings in some countries highlights the need to mobilize capital inflows from abroad, especially from developed countries, where domestic savings exceed investment. Dependence on external financing brings both benefits and risks. Financing from abroad often reduces the cost of capital and provides longer debt maturity. At the same time, over dependence on foreign investment flows can jeopardize an economy. Oversized capital inflows can be volatile and currency depreciation can increase the debt burden.

Energy projects are usually more capital intensive than projects in most other industries, involving large initial investments before production can begin. The electricity sector is the
most capital intensive of all the major industrial sectors, measured by capital investment per unit of value added [25]. The more capital intensive an industry, the more exposed it is to financial risks such as changes in interest rates and other events in financial markets. Energy investments are exposed to differing types and degrees of risk with consequences for the cost and allocation of capital. The higher the risk associated with an investment, the higher the cost of capital and the higher the return requited by investors and lenders.

Profitability is the key factor in company’s ability to raise funds for investment, whether on a corporate or a project basis. If the capital employed in a company is not generating an adequate return (measured in its own criteria) the company will have limited access to new capital.

2.4.3 Financial figures of merit

Taking into account all these elements, the assessor needs to define the financial input data required to evaluate the expenditures of funds in the construction of electricity generation plants at different times. Annex B present a short description of economic assessment elements relevant for INPRO, with enough detail to give an assessor a minimum number of tools to perform a complete economic assessment.

The value of money can be considered to change as it moves through time. The present value concept provides for the shifting of money from one time to another with a corresponding shift in its value using a discount rate, in order to represent the decrease of value due to the time drift. Theoretically, it reflects the opportunity cost of the invested capital, i.e. the return that could be achieved with the most productive investment alternative.

The difference between incomes and expenses produce the net benefit. This could be levelized using the discount rate, or the net present value (NPV) could be calculated. A positive lifecycle net present value could be taken as the levelized profit produced by the investment, if it is considered that the discount rate is the minimum rate of return or the overall cost of money for the enterprise. But the discount rate is sometimes taken at a somewhat higher value, with the argument that the rate of return must be above the cost of the funds to make the investment attractive. So, a positive lifecycle NPV could be taken as a necessary – not sufficient - condition. If an investor perceives an unusual risk for the investment portfolio he could request some additional risk reduction, by, for example, increasing the discount rate.

One usual method to evaluate a project investment is to calculate the cost levelized by the given discount rate. This is usually called Levelized Unit Energy Cost (LUEC) or Levelized Lifetime Cost (LLC) or Levelized Discounted Costs (LDC) or Levelized Discounted Electricity Generation Costs (LDEGC). LUEC (or LLC, LDC, LDEGC) is equivalent to the average price that would have to be paid by consumers to repay (compensate) exactly the costs for capital, O&M and fuel, with a proper discount rate.
Another method to evaluate an investment project is the Internal Return Rate \((IRR)\) method, an iterative procedure that determines the unknown discount rate that is needed to balance the stream of expenditures and benefits.

Return on investment \((ROI)\) is one of the major profitability variables \([24]\) and is defined as operating income divided by invested capital. As operating income is calculated before the deduction of interest and dividend payment, this definition measures the total return from a company business in relation for the total money invested in the form of borrowing or equity.

In an INPRO economic assessment two different types of financial figures of merit could be used:

1. Financial data for cost calculation: For cost comparison of different types of power plants in a general framework such as INPRO, particularly with a small amount of additional detailed information about rates for bonds, equities and other financing tools, \(LLC\) or \(LUEC\) was used in many comparative assessments \([11][12][17][18]\). So it is particularly suitable for INPRO, assessing the relative competitiveness in a comprehensive harmonized framework. To calculate the \(LUEC\) the financial rate required is the discount rate \((r)\), as is explained in Annex B.

2. Financial data for profit calculation: To calculate the profit produced by the electricity generation two different type of financial figures could be used, and different data are required:
   a. Undiscounted profit measurement: Using real values for measuring profitability without using the levelized concept, several figures could be used, like payback time or return-on-investment \((ROI)\). In INPRO, \(ROI\) will be used, and then the additional financial variable required is the reference price for unit of electricity sold \((PUES)\). The method of calculating the PUES may vary from MS to MS. In some MSs it may be obtained by modeling the grid load dispatch, from published values for the grid or by comparison with other active generation plants costs in the grid.
   b. Discounted profit measurement: Using real values, the classical figure for discounted profit calculation could be \(IRR\) or \(NPV\). For \(IRR\) the only additional variable is the reference \(PUES\), as is required by \(ROI\). So it could be easily used in INPRO. The \(NPV\) requires also a reference price, but the problem with this type of indicator is that it is not logically independent of \(LUEC\), because the discounted profit equals the difference between \(PUES\) and \(LUEC\) leveled with the discount rate. As INPRO methodology requires only logically independent indicators, \(NPV\) indicator will not be used, so no discount rate is required to perform discounted profit measurement.

These figures of merit are not unique, and the INPRO assessor could define his own figures of merit depending on the country or company investment policy. For example, a country interested in nuclear energy as an introduction of a 21st century technology will be
interested in the total levelized investment. Usually a country with this scope could evaluate
a small power reactor in competition with a research reactor investment.

To calculate the \( \text{PUES} \) computational tools like state of the art MESSAGE [3], WASP [4]
or BALANCE [25], or simple price estimation methods could be used, depending on the
scope, expertise and time availability of the assessor.

To use computer codes to calculate \( \text{PUES} \) is a task that needs to be done with proper
judgment of the deepness of the results that the assessor is looking for, because each code
has been developed with different objectives trying to include different approaches for a
very complex reality. The codes available are more complementary rather than
alternatively. Some codes have been programmed in order to do long term energy
evolution; others have been developed in order to compute short term very detailed
modeling.

Thus, expert judgment needs to be applied when an assessor wants to use complex codes
and modeling. And if there is not enough expertise available, support needs to be asked for
to perform such evaluation and calculation. International agencies and institutes, like IAEA
(Planning and Economic Studies Section) and IIASA are good examples of institutions
with special support schemes to help interested code users in energy studies and planning.

2.5 Economics and the cycle of development

The INPRO BP, UR and CR can be used as a tool to assist investors, be they governments
or industry, to assess whether or not to invest in research, development, design, and
deployment of INS. Thus, e.g., the decisions makers involved in deciding whether to invest
in the RD&D to develop a given system or component, would be expected to require
information to show that, once the INS is developed, the cost of the product provided by
the INS, e.g., energy, will be competitive with that of alternatives at the future time when
the INS is deployed. Once an INS is sufficiently developed, a decision needs to be made
whether or not to commit to its deployment. In most, if not all Member States, this will
involve another set of investors since, simplistically, deployment can be thought of a two-
step process – the offering of the INS in a given market by the developers and the
acquisition of the technology by users. Technology users need confidence, at the time a
decision is being made to commit a given INS, that once the INS has been constructed,
commissioned, and brought into service (a process that will take several years) the INS will
deliver its product at a competitive price and so enable the investor to earn an adequate
return.

In this context, it is well to consider briefly the various stages of development in bringing
an INS to the point of large-scale deployment (See Section 3.4.3 of Ref. [1], Judgement on
the maturity of INS). Firstly, preliminary work is carried out to define a concept for an INS.
Such work is often funded by national governments in Member States having significant
nuclear power programs, e.g. in national laboratories and/or in universities. One output of
such work needs to be an assessment of the potential of the proposed INS to meet national
and international requirements, as set out e.g. in the INPRO BP, UR, and CR, augmented by specific additional requirements that the Member States may have or may develop. Such an assessment also needs to identify uncertainties and the potential impact of such uncertainties using, e.g., sensitivity analysis. So, the INPRO BP, UR, and CR can be used to assist decision makers at a very preliminary stage in deciding whether or not to commit funds to invest in RD&D to advance the development of an INS beyond the preliminary stage. The proponent of an INS may seek funding and assistance to advance the development of the INS from a number of possible sources – government and/or industrial. In the early stages development may well be funded internally, but at later stages internal funds may be supplemented or replaced by external funds.

While development times vary from sector to sector, in general, the more innovative the development, the longer will be the development time and the greater will be the uncertainty concerning a successful outcome, i.e. the higher the risk of a successful development, including, in the early stages, the uncertainty in the actual cost of development. (See Table 3.3 in Chapter 3 of Ref.[1], Method for Assessment, which summarizes the different levels of technology maturity for the development and deployment).

Development times for nuclear technology can extend to tens of years. Thus, the more innovative the development is, the greater the likelihood that government support, in one form or another, will be sought. Since, the development decision is a decision to invest in RD&D, the cost of the RD&D must be estimated and an argument must be made that there will be a suitable return on the RD&D investment. For investment by industry, financial analyses will be required to demonstrate that there is expected to be a financial pay back. The justification for government investment may be partly financial but could be largely based on the strategic benefits expected to be realized, e.g. maintenance and development of industrial capacity, security and diversity of energy supply.

As development proceeds, periodic re-assessments need to be carried out to confirm, with the improved knowledge base resulting from RD&D, that targets are still expected to be met and that future investments are justified. Throughout this process, close contact between the developer and potential users, i.e. the market(s), will impose a useful discipline to ensure that the needs of the users are understood and are being addressed. At some stage, a commitment will be required to proceed with a first-of-a-kind (FOAK) plant. Prior to making such a decision significant resources will have been committed to demonstrating key aspects/components of the INS, including possibly a prototype plant, and as these aspects/components are evaluated and demonstrated, the decision whether or not to commit funds for further development and demonstration would be based, in whole or in part, on a re-assessment of the whether the development targets, e.g. the INPRO BP, UR, and CR, can still be achieved.

Where government funds have been used in development, the source of investment funds may well shift as a given INS advances towards a FOAK plant, with an expectation that industry will accept a greater share of investment as uncertainty is reduced by RD&D. Thus, as the development process proceeds, the make up of decision makers may well change. At the time of the commitment to a FOAK plant the decision makers will almost
certainly change since by definition the FOAK plant will be “commercial” plant and so will involve investment by the user, i.e., a customer, e.g., a utility. But, depending on the perceived risk, some form of government assistance or risk sharing between the developer and the customer may still be required to convince the user to commit to the FOAK plant.

For the sake of illustration, one can assume that committing a FOAK plant would require a sharing of costs (for adaptation/completion of design, construction, commissioning, and operation etc.) and/or risk among the developer, the customer/utility and government. Each would need to be assured that its investment would provide a payback. Each would look at the issue from its own perspective. In all cases, the different decision makers/investors should have an expectation that once the plant is operating it will meet requirements such as the INPRO BP, UR and CR. But each may evaluate the BP, UR and CR, particularly those related to economics, somewhat differently. Thus, for example the government may take into account spin off benefits whereas a utility would be expected to consider the return on its investment, and the developer would need assurance that he will recover any additional investment required to complete the FOAK plant (and ideally any sunk costs for RD&D already performed) from the sale and servicing of additional units.

Once a FOAK plant has been constructed, the decision makers/investors for future plants could well change again with the decision being much more a commercial decision between a customer and supplier resulting from a commercial negotiation. Governments may still be involved to a greater of lesser extent, e.g. in providing loan guarantees or, in the case of international sales, in assisting with financing. Again, the customers will want assurance that requirements will be met but, given the experience gained with the first plant risks should be lower and so customer confidence should be higher. But the situation would be expected to be different depending on the customer’s nuclear experience and knowledge.

If the customer is already an established user of nuclear technology, he may be willing to accept an INS provided that he judges that the potential risk in doing so is offset by the benefits. On the other hand, if the customer for the INS is a first time user of nuclear technology the decision whether or not to acquire a given INS may well be more complex and in this case the nature of the offer may be very different than for a customer with relevant nuclear experience. Such a first time customer will probably be a late adopter of a given technology and would not be prepared to acquire an INS (or component) until it has arrived at the stage of full commercial exploitation. Even then, he may well want the supplier to provide substantial support and technology transfer, even going so far as to want to contract for the operation and maintenance of the plant (see also Chapter 9 of Ref. [1], National, regional and international infrastructure). But in the end, this customer must also be convinced that what he acquires will deliver a product that is competitive in his market, existing or anticipated, and that given the price structure in that market he will realize an appropriate return.
Chapter 3.
BACKGROUND OF INPRO ECONOMIC REQUIREMENTS

3.1 Introduction

INPRO economics’ area has a very clear and simple structure (see Table 1.1 of Chapter 1, Introduction) of a single basic principle (BP1) and four user requirements (UR1.1 to UR1.4). For each UR at least one criterion (CR) consisting of an indicator (IN) and an acceptance limit (AL) is defined.

As stated in Chapter 3 (Method of assessment) of Ref. [1], member states may well develop their own specific criteria for each user requirement, following the definition of a criterion (CR) that specifies that they consist of at least one Indicator (IN) and one Acceptance Limit (AL) to determine how well a given user requirement is being met.

In this first version of the manual, it will be assumed that the applicant of the INPRO methodology, the assessor, is interested in electricity generation only, and therefore, at this stage, cases are not considered in which the output of the nuclear energy is different than electricity, for example, heat, desalinated water or hydrogen. To perform such type of multiple product evaluation, other methodologies need to be developed, like the excergy analysis of Ref. [27]. This type of multi product economic evaluation needs to be addressed in the medium to long-term future because it could be very important for some scenarios (refs [26][2]).

3.2 Economic Basic Principle

As set out in Chapter 2 of Ref. [1], INPRO and the concept of sustainability, energy plays an important role in each dimension of sustainable development — economic, social and environmental — and ensuring its availability is one important aspect of governments’ ultimate responsibility for national security and economic growth. Not only must energy be available but, as discussed briefly in Chapter 2 of Ref. [1], INPRO and the concept of sustainability, it also needs to be affordable. These considerations lead to the following basic principle.

Economic Basic Principle BP1: Energy and related products and services from innovative nuclear energy systems shall be affordable and available.

The best way of ensuring that nuclear energy and related services are affordable is for the price to the consumer to be competitive with low cost/priced alternatives. If energy and related products and services are to be available, systems to supply the energy and related products need to be developed and deployed. To develop and deploy innovative energy systems requires investment and those making the investment, be they industry or
governments, must be convinced that their choice of investment is wise. The alternatives for investment may be other energy technologies seeking investment for development or deployment or non-energy technology areas. So, to be developed and deployed, INS must compete successfully for investment.

As discussed earlier (Section 2.5), in different markets and regions and at different times and stages in the cycle of development and deployment the investor(s) may be different and different factors may assume more or less importance in determining attractiveness of investment. But in any case a sound business case must be made.

Given the nature of nuclear technology, it is recognized that government policies and actions (in some Member States governments may participate in investment) will have a significant bearing and influence on investor decision making, both when deciding whether or not to invest in development and when deciding to invest in technology deployment/acquisition. For private sector investment profitability and return will be key factors in the business case. It follows that if the price to the consumer is to be competitive and at the same time investors are to receive an attractive return, the cost of production must also be competitive with that of alternatives.

### 3.3 Economic User Requirement UR1.1

The definition of **User Requirement UR1.1** is: *The cost of energy from innovative nuclear energy systems, taking all relevant costs and credits into account, \( C_N \), must be competitive with that of alternative energy sources, \( C_A \), that are available for a given application in the same time frame and geographic region.*

The first user requirement relates to cost competitiveness which, as discussed in the introduction, is a requirement for the INS is to be both available and affordable. In determining the cost of energy (or other products) from INS and competing alternatives all relevant costs must be included. Depending on the jurisdiction, one energy source may be burdened with costs, e.g. for waste management, while another may not. In a number of Member States, the external costs of nuclear power\(^1\) that are not accounted for are small since producers are required by law to make provisions for the costs of waste management, including disposal, and decommissioning whereas the external costs of competing energy sources that are not accounted for may be significant. Ideally all external costs should be considered and, where possible, internalised, when comparing INS with competing energy systems.

Costs are not static but vary with time. In principle, such variations can be taken into account in the cash flow analyses required to calculate a LDC for \( C_N \) and \( C_A \). But, one Member State has noted that in the case where the LDC of the competing energy source is sensitive to the fuel cost, e.g. combined cycle gas turbines, and where there is an expectation that the fuel cost is expected to increase dramatically in the future, it is useful

---

\(^1\) By definition an external cost is a cost imposed on society and the environment that is not accounted for by the producers and consumers of energy.
to compare the LDC of the INS with the expected annual cost for the competing energy source to determine how the competitive position of the system changes with time. In such a situation, a significant benefit would result from up front licensing and site selection work for an INS, particularly if the INS had a short construction and commissioning time. Then, a utility could track the increasing operating cost for the high fuel cost option against the LDC for the nuclear system and so be more confident that the competitive advantage had shifted to the INS when committing to its construction. The shorter the time between making such a decision and the time to bring the nuclear plant on line the smaller would be the risk to the utility in making such a commitment.

Depending on the nature of the dominant competing energy technology(ies), locally, or nationally, at a given point in time and in a given region/country, acceptance limits may be defined for specific cost determinants, e.g. specific capital cost. Here it may be noted that the high capital cost of nuclear makes the LDC for it sensitive to the discount rate while the LDC for fossil fuel plants are sensitive to fuel costs [28].

In the near to intermediate term (over the next 20 to 50 years) in many Member States, fossil-fired thermal plants, e.g., coal-fired or combined cycle gas turbines, are likely to be the prime competition with nuclear for electricity production (see Section 4.1.1 of Ref. [26]). Thus, reductions in the specific capital costs of nuclear power plants while maintaining low fuel and O&M costs, as well as waste management and decommissioning costs, would improve the competitive position of INS.

As noted in Chapter 2 of Ref.[1], INPRO and the concept of sustainability, renewable energy sources (e.g. hydro, wind, solar, biomass) are predicted, in the SRES scenarios, to increase considerably their share of global energy supply, especially in the latter half of the 21st century. Thus, in the longer term, renewable energy sources such as photovoltaics and wind power may represent the primary competition for nuclear energy. These technologies are characterized by low, if not 0, fuel costs and, if successfully developed, low maintenance costs. The main cost is the capital cost of construction and installation, including the capital cost for back-up storage and/or alternate sources of energy and the ‘cost’ of land use. Because of their inherent nature, renewable energy sources such as wind and solar do not generate power continuously. So, as they gain market share, it becomes increasingly important to provide back-up sources and the cost of doing so must be taken into account. The higher capacity factors expected from nuclear technologies compared with those from renewables represents a competitive advantage for nuclear. In recent years average availability factors >90% have been achieved. With INS even higher availability factors, ~95% should be achievable.

In some jurisdictions, land use can be an important factor, in which case it might be adopted as an indicator. The latter is sometimes treated as a ‘rent’ and hence becomes, in effect, analogous to a fuel cost. Alternatively, land use costs may be considered an owner’s cost. The much higher energy output of nuclear plants for a given plant footprint, MW(e)/hectare, is one of nuclear technology’s competitive advantages compared with renewables (see for example Ref. [32]).
If the total unit energy cost of nuclear energy is to be competitive, the cost of the fuel used in the energy production machine – the reactor – must remain low. The operator of a nuclear energy plant will act as a customer for the products from fuel cycle facilities and innovative fuel cycles must be competitive with alternate fuel strategies, which may be coupled with alternative reactor designs. Thus, the capital cost and the operating and maintenance costs of the nuclear fuel cycle facilities other than the reactor must be sufficiently small that the fuel costs to the reactor operator are competitive. Fuel cycle facilities also produce waste, which must be safely managed, including placing it in a safe end-state and, in due course, the facilities have to be decommissioned. The cost of all these activities and the associated waste management facilities must be such that the fuel costs remain competitive.

Overall, it is clear that, for INS, the capital costs, the operating and maintenance costs, the fuel costs, the waste management costs, and the decommissioning costs must individually and collectively be sufficiently low to make the total unit cost of the energy product competitive. Thus, from an economic perspective, the INS need to decrease overnight construction costs, decrease construction times and hence interest during construction, decrease O&M costs, increase life cycle average availability, and extend plant lifetimes, all without compromising safety or environmental performance.

The background of all economic indicators and acceptance limits will be described and discussed in the following.

3.4. Indicators and Acceptance Limits of UR1.1

The general indicators defined for this UR are: IN1.1.1. Cost of Nuclear Energy $C_N$ and IN1.1.2. Cost of energy for alternative sources $C_A$.

As discussed in Chapter 3 (Method for Assessment) of Ref. [1], Member States may well develop their own specific criteria for each user requirement. One criterion would be based on a comparison of $C_N$ and $C_A$ with an acceptance limit that $C_N/C_A<k$, where $k$ is a factor that can be less than or greater than one in a given Member State or region depending on whether or not nuclear costs are offset by credits relative to the alternative energy source or vice versa. Thus, Member States and investors will determine the value of $k$ depending on their particular circumstances. Such a determination could well be made in the decision making process as part of taking into account factors to which it is hard to assign definitive costs, such as the cost of externalities. Thus the argument in favour of a given choice may well be phrased more or less as follows: ‘Option N is slightly more costly that option A but the following benefits of option N compared with option A more than outweigh the cost disadvantage and hence option N is preferred.’ But, as well as being cost competitive, if the energy product is to be profitable, the cost must still be smaller than the selling price in a given market to provide investors with a profitable return.

In a given country/region many factors can enter into the decision-making regarding the choice(s) of energy supply. These include, for example, considerations of security of energy supply, long term stability in energy costs, diversity of energy supply technologies, i.e. the energy mix, of both the market as a whole and of the a given producer/supplier; the
desire for industrial development and the role nuclear technology can play in such development; judgments about environmental impacts, either positive or negative, avoided emissions, safety, sustainability, waste management; utilization of domestic resources, such as mineral and labour resources and industrial capacity; public and hence political acceptance (see also Chapter 9 of Ref.[1], National, Regional and International Infrastructure), etc. Such considerations may lead decision makers and investors, particularly governments, to accept a somewhat higher cost for one energy option compared with an alternative. See, e.g., Refs [33, 34], which discuss the credit that could be assigned to security of energy supply in Japan. As circumstances change so may the value of $k$ that will apply in a given country/region. In the longer term, market forces would be expected to constrain the value of $k$ to be close to unity.

$C_N$ and $C_A$ should be calculated using a levelized discounted cost (LDC) model (see, e.g., ref. [20]) taking into account all relevant cost determinants for both the INS and the competing energy technology. In making such cost comparisons sensitivity analyses should be employed to assess the impact of possible changes in costs such as O&M costs and fuel costs. Further, the cost comparison should be based on costs for the relevant region/market and the time frame for the deployment of the INS, using energy planning tools (see, e.g., Refs [3, 4]) to arrive at the best quantitative estimates of the various cost components.

Costs should be based on the costs for repeat units or $N^{th}$ of a kind (NOAK), rather than for a first of a kind unit (FOAK). The model should be transparent and complete. Cost determinants include the following: specific capital costs for overnight construction, financing costs, including interest during construction (IDC), operating and maintenance costs, regulatory costs, fuel costs, the cost of periodic upgrades expected over the anticipated plant lifetime, such as the replacement of I&C systems or the refurbishment of steam generators, capital discount rate, owner’s costs and in particular land use costs, the anticipated capacity factor, which takes into account among other things the availability factor and the load factor, insurance costs, the plant lifetime, net electrical output taking into account thermal efficiency, construction/project time, labour rates for engineering and construction, operating and contracted staff complements, amortization period, fuel burnup, decommissioning and waste management costs, credits/penalties applied, e.g., credits for avoided emissions or industrial benefits, etc. Further, at the time that investment is being made in developing INS, the cost estimate (for the product of the INS) should include a component to recover the development costs with a suitable return.

For an INS, many of these costs, particularly at early stages of development (see Section 2.5), may have uncertain values, and hence may encompass or require ranges of estimates. Thus, sensitivity analysis should be used in assessing the impact of potential variability in costs. Such sensitivity analysis can be used to identify the relative importance of the various cost determinants and also to identify opportunities for cost reduction. The completeness and the ranges of the cost determinants may be regarded as a measure of the maturity of the INS design. As the INS proceeds through the stages of development (conceptual, feasibility, prototype, first of a kind) the cost estimates will be refined and the uncertainties reduced. But costing an INS as it evolves is an important and necessary discipline to ensure that is will be cost competitive.
A more precise indicator definition of IN1.1.1 could be written as follows:

**Indicator IN1.1.1** is defined as: $C_N$, the single Levelized Discounted Cost of the complete INS ($LDC_N$), or is even more precisely defined as: The single Levelized real discounted Unit net generated Electricity plant’s life total Costs ($LUEC_N$) for the complete INS, excluding FOAK cost, including external costs and credits if they are fully included in the price setting mechanism, using contingency allowances and a discount rate that reflects the economic decision making investment environment.

**Indicator IN1.1.2** is defined as: $C_A$, the single Levelized Discounted Costs ($LDC_A$) for the cheapest alternative $A$, or is even more precisely defined as: The single Levelized real discounted Unit net generated Electricity plant’s life total Costs ($LUEC_A$) for the strongest competitor power generation investment option $A$, excluding FOAK cost, including external costs and credits if they are fully included in the price setting mechanism, using contingency allowances and the same discount rate as applied in the $C_N$ calculation.

These definitions specify several items to be included and excluded in the indicator:

- If the INS includes several reactor types (e.g., some reactors producing plutonium and others recycling the Pu) the single net electricity costs need to be calculated. This avoids the problems produced in the evaluation of such INS with several reactor types with different costs at different times and different production scales.

- Exclusion of FOAK costs is appropriate here because the indicator has not been selected to quantify the R&D and demonstration costs. The indicator is to be based on the costs of an NOAK (once the technology is fully commercialized), recognizing that the commercial price of a product, such as a NPP, would normally include a profit component to payback the developer’s investment. Other INPRO basic principles and indicators need to be developed to evaluate R&D and FOAK costs.

- Total cost for the complete INS, including all the materials required for the plant’s life, from the mining and plant construction, including the first core up to the backfitting, decommissioning and waste management for all the plants and activities in the INS.

- External costs and credits could be added if they have a specific price setting mechanism, excluding external costs and credits that have been measured in the same unit as electricity costs but that don’t have a mechanism to combine them with internal costs.

- The time period for electricity generation needs to be the plant’s life, in order to exclude an amortization time period different from the technical life, and to avoid other amortizations approaches that could be inconsistent with waste management and decommissioning and backfitting costs.
The concept of levelized real costs implies that for a given time base, prices without inflation need to be used. This time base is selected by the assessor, and due to the inherent nature of real costs, these values could be time dependant due to many factors other than inflation. This could imply a situation evolving with time for both $C_N$ and $C_A$. If it’s relevant for the assessor, both $C_N$ and $C_A$ could be taken as time dependant values: $C_N(t)$ and $C_A(t)$.

The discount rate used for this indicator needs to be the same for $C_N$ and $C_A$, and related with the values used in the investment decision making process in the electricity sector, because R&D have been excluded together with other external costs and credits.

Contingency allowance needs to be included in the plant costs, systems or components, with values that depend on the maturity level, departure from previous experience or quality level for the potential impact on plant condition and safety. For innovative nuclear plants Chapter 3 and appendix H of Ref. [22] could be a very useful guideline.

In selecting alternatives (non nuclear) the strongest competitor for the generation costs or cheapest alternative has to be chosen. This implies that if several alternatives are available, only the cheapest could be selected as $C_A$. However, as competitiveness is an inherent moving target [28], in a situation evolving with time the cheapest alternative could change from one energy option to another option depending on the scenario. Additionally, the scenario needs to consider future price changes and uncertainties. E.g., is a given fuel price expected to increase or decrease with time?

**Acceptance Limit AL1.1:** $C_N/C_A<k \text{ Where } k \text{ is a factor less, equal or greater than one fixed by the assessor taking into account other costs and credits not included in the indicator calculation}

Without other factors considered, usually in an investment evaluation it is required that $k=1$, emphasizing that this is a not sufficient economic condition or the end of the evaluation procedure. But for an INPRO assessment, dealing with medium and long term planning, innovative systems, and R&D policies this is too restrictive a requirement. Furthermore, different assessors will have very different needs to be reflected in this acceptance limit.

There are factors that could be reflected in requesting $k<1$, for example:

- An assessor (e.g., government or private industry) is interested in funding R&D of a nuclear technology only if this technology has a promising perspective to be significant cheaper in comparison to alternative (non-nuclear) energy sources.

- An assessor is interested in having a nuclear alternative with enough difference to the competitors to be sure that this alternative will be deployed in a significant scale, with the support of many players.
An assessor wants to be protected from a perceived higher risk of $C_N$ (e.g. investment in nuclear) compared with $C_A$ (investment in non-nuclear).

And there are factors that could be reflected in allowing $k > 1$, for example:

- Economic and non-economic factors not included in $C_N$ or $C_A$ but for which the assessors are willing to pay a given fraction of the cost of the alternative.
- An assessor that wants to be protected against a perceived higher risk of $C_A$ compared with $C_N$.

And there are factors that could be reflected in $k \neq 1$, for example

- A significant difference of needed hard currency share between the alternatives.
- A significant difference of needed local resources and labor between the alternatives.

All these bullets above are only very general examples that could be used to define $k$. The assessor using the INPRO methodology needs to be reminded that each INPRO indicator and its acceptance limit is only an individual assessment of a particular user requirement, logically independent of the others indicators, and there is no contradiction into requiring simply $k=1$, and to use other INPRO sections to take into account other factors not included in the economic assessment.

### 3.5 Economic User Requirement UR1.2

The definition of **User Requirement UR1.2** is: *The total investment required to design, construct and commission innovative nuclear energy systems, including interest during construction, should be such that the necessary investment funds can be raised.*

The total investment required to deploy a given INS, or component thereof, comprises the costs to adapt a given design to a given site, and then to construct and commission the plant, including the interest during construction. The latter depends on construction time and the time to commission. A universally applicable criterion for what constitutes an acceptable ‘size’ of investment cannot be defined a priori since this will vary with time and region and will depend on many factors such as alternatives available, etc. But a judgment must be made that the funds required to implement a project can be raised within a given expected investment climate. Factors influencing this ability may include the overall state of the economy of a given region/country, the size of the investment relative to a utility’s annual cash flow (and hence the size of the unit relative to the size of the grid), and the size of the investment compared with that needed for alternative sources of supply. When comparing investments required for alternative sources of supply the cash flows during construction and commissioning for the different options are important. One way of comparing these is to use the discounted capital costs of the options. It may be noted in setting specific development criteria, that a judgment concerning the capacity to raise investments of a given amount for investment in a given region can be obtained from a
review of the historical investments in that region, particularly those in energy supply. In the end the investment in an INS must be affordable and attractive in a given investment climate taking into account other investment options and other priorities requiring a share of available capital.

### 3.6. Indicators and Acceptance Limits of UR1.2

Investors look at a variety of financial indicators when evaluating investments including internal rate of return (IRR), the closely related indicator, net present value (NPV), payback period, return on investment (ROI), etc. The financial indicators used in a given region will reflect the investment climate and requirements of a given country/region, including the source(s) of investment funds. In some countries/regions INS will require private sector investment while in other countries/regions INS may require government investment or guarantees. Private sector investors will be attracted by a competitive IRR, provided the IRR is commensurate with their judgment of associated risks. As noted NPV and IRR are closely related but net present value analysis may facilitate taking into account other benefits such as security of energy supply and technology development that may be of more interest to government investors than private sector investors. Return on investment (ROI) may be attractive as an indicator complimentary to IRR, since it is more independent of IRR than NPV. In the end, the acceptance limit is that the values of the financial indicators chosen, for a given INS, be attractive compared with investments in competing energy technologies. Thus, they must be at least comparable to the values for competitive energy sources and preferably better.

As set out in Table 1.1 of Chapter 1, the general definition of the indicators are: IN1.2.1. Financial figures of merit, and IN1.2.2. Total investment.

For indicator IN1.2.1 two financial figures (IRR and ROI) of merit have been chosen, as follows:

**Indicator IN1.2.1.1** is defined as: *The Internal Return Rate (IRR) at the calculated real selling price of electricity produced by the complete INS (IRR_N)*, or even more precisely defined: *The IRR produced by selling the net electricity produced by the INS at the defined real PUES, excluding costs not defined in price setting mechanisms and including costs for confident lifecycle operation, decommissioning and waste treatment.*

This definition specifies that:

- The IRR needs to be calculated without considering inflation in prices or “real” prices. Thus, time dependant price changes need to be the price changes for other reasons rather than inflation. Price changes other than inflationary changes could come about for a variety of reasons, for example, by a change in the price – demand relationship, a discovery of or depletion of specific resources, regulatory changes, etc.
The IRR needs to be calculated for the total cash flow of the complete INS, including all the power plants and fuel cycle facilities within the defined INS. When fuel cycle facilities sell their products additionally to other clients that are not part of the INS, the price for products supplied to the INS need to be calculated appropriately taking into account price elasticity, depletion of resources, etc.

Only economic elements that are defined in the price setting mechanism should be considered. Elements should be excluded if they are not supported by an acknowledged price calculation tool. This is applicable for both costs and credits.

All the expenses and incomes need to be computed for the total plant cycle operation, including backfitting and life extensions, if there are applicable. Also decommissioning and waste treatment need to be taken into account.

If the system is not carefully designed from the financial point of view, the credibility of the well established IRR method could be challenged for very complex INS. Complex cash flows, with several time periods of negative cash flows (produced by decommissioning or the construction of several related plants) will produce more than one value of IRR. In that case, IRR couldn’t be formally calculated and then it could become a “risky” INPRO indicator. If a cash flow has several IRRs, unrealistic financial “advantages” could be calculated, if IRR is used as a figure of merit. For example an inefficient plant operation could produce an increase in the IRR. This is an inherent limit of all classical financial figures of merit for very complex cash flows. For these cases other less sophisticated or simpler indicators could be used without this disadvantages.

Indicator IN1.2.1.2 is defined as: The Lifecycle plant average Return of Investment (ROI) of the complete INS (ROI\textsubscript{N}), or even more precisely defined: The ROI calculated for the average lifecycle total plant invested capital and lifecycle average operating net incomes produced from the sale of electricity.

These definitions specify:

- Only capital invested in the electricity production machines is included in the calculation of ROI, and decommissioning and/or waste treatment investments are excluded. But such costs could be taken into account as an operating expense and could be subtracted from the total income. For very complex INS, with several plants of several types, an average investment per plant, a single ROI could be calculated using the average operative incomes and investment per plant.

- Lifecycle plant investment means that all the investments required for the operative lifecycle plant, including back fittings or major refurbishments are taken into account, if they are needed during the operating lifetime of the plant.

- Lifecycle average operative incomes cover the situation that there could be some fluctuations in the operative income during lifetime (e.g. due to a low load factor during a back fitting period, or during the first operative years); the lifecycle
average incomes are the values that are preferable or best suited to calculate the ROI.

- Since only electricity generating plants are included in the investment for calculating ROI of these plants, investment in necessary fuel cycle facilities are excluded from this indicator, albeit that the required investment will be reflected in the fuel costs used to calculate net income. But an investor in a fuel cycle facility will be interested in the ROI on his investment taking into account his investment and his income from the sale of the fuel product from the facility. Other types of secondary financial figures of merit may also be considered when considering investment in fuel cycle facilities. For some countries a high local investment in such facilities may be attractive to reduce hard currency drain to other countries, while for other countries it could be a disadvantage because there is no need for local participation in fuel production activities. An INPRO assessor needs to take special care to assure that the fuel costs used in his assessment reflect the real infrastructure required for the scope of deployment defined in his INS. For example if the assessor is interested in analyzing an INS, on a fully commercial basis, that uses enriched uranium with more than 5% enrichment, he needs to use enrichment prices that reflect the future expansion of new enrichment services, using enrichment plants amortized with a higher discount rate.

- Considering that ROI is a rather simple financial variable, this variable could be calculated for any INS cash flow, with several sign changes during the lifecycle of the system.

**Acceptance Limit AL1.2.1.1:** $IRR_N > IRR_{LIMIT}$ Where $IRR_{LIMIT}$ is the minimum acceptable level required by the investor for competing technologies of comparable size

**Acceptance Limit AL1.2.1.2:** $ROI_N > ROI_{LIMIT}$ Where $ROI_{LIMIT}$ is the minimum acceptable level required by the investor for competing technologies of comparable size

Without other factors, usually in an investment evaluation it is required a minimum level of $IRR_{LIMIT}$, this is very common in many investment projects. To select an acceptance limit several factors could be considered:

- The minimum acceptable level is that the financial figures of merit need to be comparable or better than competing technologies of comparable size.

- It's clear that if it is enough for an assessor to have an INS comparable in the financial figures of merit, it is very simple to create these limit values by direct comparison with alternatives, or take them from studies done in the energy sector at a comparable power level.

- But if the assessor is aiming to select an alternative particular advanced in its financial figures of merit, the limit could be fixed looking for better values. In that case it will depend on the assessor what could be an acceptance limit.
The $IRR_{LIMIT}$ could be taken, for some assessors as a risk protection for the investor. So they could ask higher values compared with other energy projects of similar size, if they perceive that the risk is larger compared with competitive projects of similar size.

**Indicator IN1.2.2** is defined as: *The highest single plant total investment up to commissioning the reactor within the complete INS.*

The indicator implies:

- For a very complex INS, that includes several types of reactors with different technologies and power output, the reactor that requires the highest investment needs to be selected for this indicator, because it will be the weak link in the overall investment chain.

- Total investment includes all the direct and indirect costs, including owner’s costs and contingency margins. Interest during construction needs to be included, the size of which depends on construction time and the commissioning time.

- FOAK Costs, together with R&D costs would in general not be explicitly included in this indicator, because such costs are different from simple electricity oriented fund-raising mechanisms, and are more related with R&D investment policies used by governments and/or private investors. But should a company (utility) consider the purchase of a reactor requiring significant FOAK investment, the company could negotiate with the supplier future price reductions for additional orders, or even some participation in the supplier’s sales. In such a case, FOAK investment could be analyzed using different variables/parameters. FOAK and R&D costs born by the developer would be expected to be reflected in prices quoted by a vendor/developer and so such costs may be implicitly included.

**Acceptance Limit AL1.2.2**: $IN_{N} < IN_{LIMIT}$ Where $IN_{LIMIT}$ is the maximum level of capital that could be raised in the market climate.

Depending on the scale of the required investment, the capability to raise the fund depends on several issues:

- The factors that are included in the decisions made about investment. These factors could vary from considering a pure market-based competition in the electricity sector to factors relevant to centralized state planning, should the capital investment be made by a (federal) government.

- In all cases the player in the decision making process will have limits in the mechanisms for investment.
A market oriented approach could be based on raising funds from external investors or a company (e.g., utility) could use its own capital resources to fund the capital required for the investment in new plants.

A state oriented approach could ask for other mechanisms in which the limit could be derived as a fraction of the investment budget to be used in the energy sector.

The limits could depend on the currency that is required, because for countries with limited amounts of hard currency, the main limitation could be not only the total investment, but also the investment in foreign currencies.

Thus, the limits are very strongly dependent on the investment environment in which the INS is to be deployed.

### 3.7 Economic User Requirement UR1.3

The definition of **User Requirement UR1.3** is: *The risk of investment in innovative nuclear energy systems should be acceptable to investors taking into account the risk of investment in other energy projects.*

Investor risk comprises several factors, including among others, uncertainties in basic project cost, the cost of project delays, adverse public pressure, and shortfalls in plant operation.

Uncertainties in project basic cost estimates has been discussed above, under economic UR 1.1, and as noted there, sensitivity analysis should be used in estimating the potential variability in costs and the results of such analyses should be taken into account in assessing risk. Such sensitivity analyses can be extended to assess the sensitivity of the financial indicators, e.g., IRR, to changes in a variety of cost parameters, including overnight construction costs, project execution times, discount rate, etc. The results of such analyses would be expected to affect the hurdle rates employed in the financial analyses called for in economic UR 1.2. Hence, a separate criterion related to project cost estimates has not been specified.

### 3.8. Indicators and Acceptance Limits of UR1.3

The general indicators (IN) defined are: IN1.3.1. *Licensing status*, IN1.3.2. *Project construction and commissioning times*, and IN1.3.3. *Relevant indicators of the political environment show long-term support for nuclear power.*

More precise indicator definitions could be written as follows:

**Indicator IN1.3.1** is defined as: *A number between zero to one that represents the level of licensing approval by a regulator required to start the construction of a reference or specific plant.*
Regulatory uncertainties can result in investor risk as would failure to meet basic requirements, such as those related to safety, environment etc. Thus, the demonstration of compliance with requirements, e.g. INPRO BPs, and URs in all areas, is important in minimizing plant performance risks and, also, regulatory risk. Generally, in case of an innovative design (an advanced design, which incorporates radical conceptual changes in comparison with existing practice), construction and operation of a prototype or a first of a kind plant will provide confidence that technical risks have been covered and lay the foundation for pre-licensing in the country of origin, thereby further minimizing risk for larger scale deployment. Thus, there is an expectation that the technology has been adequately demonstrated as part of the innovation and technology adoption process.

When considering this indicator, the following should be noted:

- Different countries require different regulatory approvals to start the construction of a nuclear reactor. Some countries require a certification of the design by supplying the final safety analysis report, and other regulatory bodies require the approval of a preliminary safety analysis report to authorize the start of construction. Environmental clearances are usually a requirement for obtaining regulatory licensing approval. Such approvals are usually required also for other non-nuclear large-scale energy production plants.

- Some countries require a site-specific analysis while other countries require a demonstration that the site characteristics are included in the design envelope of the designer.

- From the investor’s point of view, obtaining a construction permit does not ensure that the reactor will be approved for starting operation, but it demonstrates that the design approach is on the right track.

- From the investor’s point of view, the risk is dependant on the project status. For a decision to start construction, information related to construction is required. More information, like a permit for starting power generation, will reduce the risk of this indicator even further.

- A value of zero of the indicator implies that there is not yet a formal application to the relevant safety authority to start the licensing process.

- A value of one of the indicator implies that the relevant safety authority has certified or approved the start of construction of the plant.

- Intermediate values of the indicator between zero to one are obtained by simply defining the number of all intermediate licensing steps between the two extremes and calculating the ratio of the level achieved for the INS in the licensing process and of the total number of licensing steps. Since the licensing process is country specific the value needs to reflect country specific conditions.
If there are several reactors and facilities in the INS and all plants and facilities are needed, the constraining value is the lowest value, representing the licensing status for the plant that is at the earliest status of the licensing process.

This indicator could be seen as representing the effort and risk to fulfill the prerequisites for a construction permit.

**Acceptance Limit AL1.3.1:** The status of licensing \( \text{Licensing} \geq \text{Licensing}_{\text{LIMIT}} \), this means that the maturity of licensing has to reach an acceptable value depending on the time available till the date for deployment.

This acceptance limit requires:

- The licensing status needs to be advanced enough to assure a sufficient small risk for the construction.
- A minimum acceptable limit needs to be the capability to be ready to sign a contract to start the construction.
- The licensing status could be sufficient if such a status is achieved in the country of origin, if such standard is relevant.
- In other cases the standard of the country of interest of the assessor needs to be satisfied.
- If the assessor is interested in a ready to be deployed plant, the acceptable limit could be taken as 1.
- If the assessor is interested in a plant for medium or long term, smaller values could be acceptable.

**Indicator IN1.3.2** is defined as: The time span between the first contract for the plant construction and the start of commercial operation.

Project delays lead to cost overruns, particularly in project management and engineering support costs and in IDC. The greatest impact of project delays, particularly on IDC, arises during construction and commissioning. Thus, the time taken to construct new facilities and to bring them into operation (and so to start to generate revenue) should be as short as practicable and specific targets can and should be set as development objectives for INS.

In assessing the time taken to design, construct and commission a new plant it needs to be recognized that front end design work, environmental assessment, and licensing applications, while potentially lengthy, represent a relatively small investment compared with the investment required to procure, construct, install, staff and commission new facilities. Commissioning comes at the end of the process when the majority of investment
funds have been expended and when the rate at which interest during construction accumulates is largest so it is important to minimize the duration of commissioning.

Different plant designs may have different project execution times. Recent construction times for reactor projects have been as short as 52 months (first concrete to criticality) and commissioning periods from first criticality to full power have been as short as 2-3 months for repeat projects. Thus, a construction period of 48 months is judged to be an achievable target, at least for reactors, within the near future. In due course, with innovation, use of in-shop modular construction, and for repeat plants, construction periods as short as 36 months might be achievable.

The following may be noted:

- From the economic point of view, the indicator reflects the time between the date the first contract was placed (that would produce a commercial significant consequence should the project be subsequently stopped) and the start of commercial operation, which is assumed to be the point in time at which the plant begins to produce a predictable and reliable revenue stream and hence the point in time when recovery of the investment begins.

- Other construction milestones, such as the start of activities in the field or pouring of first concrete, are classical engineering milestones, but they are not as relevant from an economics perspective as the milestones specified above. Sometimes modularization (an attractive objective for reducing several construction costs) increases the importance of the first contracts [29], because each module forces the utility to reach a price agreement (and related down payment) of the overall content of one module instead of only committing to the cost of a limited number of parts on the critical path.

**Acceptance Limit AL1.3.2:** The construction time $T_{CI} \leq T_{CLIMIT}$ for a comparable plant with a different energy source.

This indicator requires:

- For INPRO, a comparable energy source usually could be taken from a relevant competitor. Comparable means that it should have a similar size (e.g. power output) compared with the reference plant.

- Then the assessor needs to define what could be a tolerable higher percentage of construction time compared with the alternative, from the point of view of risk of the investment.

- In that case the value could be taken for the construction time of the alternative: $T_{CLIMIT} = (1+f)T_{CIA}$ in which $f$ is positive real value usually lower than one.
**Indicator IN 1.3.3** is defined as: *A political long term commitment showing support for nuclear power in construction permit, operation support, decommissioning and back end issues, from the investment point of view.*

Another factor that needs to be considered is whether or not the political climate is supportive of the use of nuclear power and whether such support is likely to be sustained over time scales of interest.

The indicator implies the following:

- Depending on the legal and social structure of each country, the political commitment could be demonstrated in different ways. The assessor needs to define by a logical yes/no indicator if the political support is adequate for the investment (see discussion of the political climate later in this section).

- It is recognized that public opinion is an important factor in developing and maintaining political support and public policy.

- The support needs to be demonstrated in the different stages of power generation commitment. From the investor’s point of view, he is exposed to different types of risk during a project: during construction, operation, and decommissioning and final disposal of high-level waste.

- Political long time commitment is required to avoid a high discount rate or IRR that could be used in a non-stable political situation. Sometimes the discount rate could be higher due to competition of rising funds in the capital market, or because there is a perception that the conditions for an economic operation could be sustained only for a short period. In addition, experience clearly shows that the political support is critical for many other factors very relevant for economics, like the fund rising capacity, contingency margins, etc.

- The indicator is a logical yes/no condition, depending on the commitment shown by a specific member state. For example, a law for nuclear waste management in countries in where there is a strong tendency to relate each activity to its own (and specific) legal structures is an important issue.

In assessing the risk of investment in innovative nuclear energy systems the “political climate” should be considered to determine whether there is political support for nuclear power, whether such support is likely to be sustained, and whether investments made in INS would be protected should the climate change. The corresponding general indicator is the question:

- “Can a potential investor be assured that his investment will be protected from political interference until it has been paid back?”

The acceptance limit is a positive answer to this question. The nature of the assurance may be different at different times and places. Assurance may be obtained by assessing a variety
of factors. For example by asking the following questions the investor can identify whether there is a significant risk:

- Does a country have an energy strategy that recognizes that nuclear power is an essential component of its energy supply mix? Necessary is a positive answer to this question.

- Do both the governing party and the leading opposition party support nuclear power? Necessary is a positive answer to this question.

- Is there a political party that is actively opposing nuclear power? Necessary is a negative answer to this question.

- Has progress been made in addressing controversial issues such as the siting of end-state waste management facilities? Necessary is a positive answer to this question.

- Is the legal system such that interveners can unduly delay projects? Necessary is a negative answer to this question.

- Is there a system for resolving public concerns prior to committing significant project funds? Necessary is a positive answer to this question.

- Is the regulator independent? Necessary is a positive answer to this question.

If all questions above are answered satisfactorily, the risk due to a change of political climate could be declared as tolerable. However, if the investor identifies a potential risk (e.g., via the questions above), he may still be prepared to invest if he can protect his investment, if the risk is realized. To check the possibility to protect his investment in case of a risk, the following questions have to be addressed:

- Is there legal recourse to recover investments in the event of state interference, e.g. nationalization? Necessary is a positive answer to this question.

- Has there been adequate compensation to investors in such circumstances in the past? Necessary is a positive answer to this question.

- Can assurances be obtained that investments will be protected against such interference, for example, by state-to-state agreements, contract or export insurance provisions? Necessary is a positive answer to this question. Examples for such assurances or measures that provide protection against loss of investment in case of a change in the political climate can be found in section 11 of Ref. [25].

To make the risk tolerable in such a situation the questions above should be answered in a positive way.

Acceptance Limit AL1.3.3. Yes.

The acceptance limit implies:
Even in pure market condition it is a necessary condition to have political commitment for peaceful uses of nuclear energy.

This condition is a prerequisite for any INS.

Without such support, many other acceptance limits couldn’t be sustained, because to overcome the risk of unstable political support will produce too much conservative values to be sure that the INS is an attractive means.

Without fulfillment of this acceptance limit it creates a coupling among all types of indicators that results in a no longer logically independent structure of indicators.

### 3.9 Economic User Requirement UR1.4

The definition of User Requirement UR1.4 is: *Innovative energy systems should be compatible with meeting the requirements of different markets.*

Given the uncertainty about the future, as reflected for example in the wide range of possible future scenarios considered in the SRES (see Ref. [5] and Section 4.1 of Ref. [26]), INS should be sufficiently flexible to be able to evolve and adapt in a manner that provides competitive energy for as wide a range of plausible futures and markets as possible. Thus, the ability to adapt specific components of an INS, as well as the overall adaptability of the INS, to accommodate different sized modules, to accommodate market changes and growth, to accommodate different fuels, to meet different energy applications, and to meet the needs of different countries/regions is desirable. In assessing flexibility of a given component or set of components, possible synergisms with other components of the INS should be considered.

### 3.10 Indicators and Acceptance Limits of UR1.4

The general definition of the Indicator IN1.4.1 is: Flexibility (Robustness) of INS.

The indicator is somewhat vague but it can be related to the basic principle that states that an INS needs to be affordable and available. Thus, the indicator seeks to measure whether the INS has sufficient robustness to changes in assumptions that acceptance limits will still be met under different market conditions and so be: available and affordable under different market conditions. Thus, the indicator could be defined more precisely as follows:

**Indicator IN1.4.1** is defined as: *The distance of the value of the most sensitive economic indicator to its limit value for other market conditions, or even more detailed defined: The Robustness (Flexibility) Index (RI) for the most critical economic indicator obtained by comparing the change in the value of the critical indicator for a different market condition with a specified tolerable limit value.*

The definition implies the following:
The assessor has to specify the critical economic indicators \( i_e \) from his perspective and interest.

For the critical indicators the assessor has to define a lower tolerable limit \( i_e^{UL} \) or an upper tolerable limit \( i_e^{UL} \) depending on whether the indicator has to be less than or greater than a limit value.

The tolerable limit value may not necessarily be the same as the acceptance limit, because the limit value is seeking to determine a value for market conditions that are different from the value for the reference scenario.

For the critical indicator, the assessor needs to define which of the data \( d_i \) that are used to calculate it, might deviate from the reference value because the market evolved to a different scenario.

For these data, the assessor needs to calculate the upper and lower limits for different conditions reflecting different future market conditions.

For the worst case data change \( d_i \pm \Delta d_i \), formulae (27), (28) and (29) of Annex B should be used to calculate the value of the perturbed indicator, \( \Delta_i(d_i \pm \Delta d_i) \).

The Robustness (Flexibility) Index (RI) could be defined as the ratio between the tolerable limit of this indicator and the worst case value of the perturbed indicator if the tolerable limit is an upper limit:

\[
RI_{i_e,d_i} = \frac{i_e^{UL}}{\Delta_i(d_i \pm \Delta d_i)}
\]

If the tolerable limit is a lower limit, the \( RI \) is defined as the ratio between the worst case value of the perturbed indicator and the tolerable limit.

\[
RI_{i_e,d_i} = \frac{\Delta_i(d_i \pm \Delta d_i)}{i_e^{UL}}
\]

The \( RI \) is defined in order to increase when indicator values have more distance from the tolerable limit. Then the INS is called “more flexible” in such a case, and would be “less flexible” if the indicator values would be closer to the tolerable limit or even exceed the acceptability range of the perturbed values.

For the robustness (flexibility) point of view the perturbation could be applied in a broad sense. For example the change on uranium price could force a change from an OT fuel cycle to a plutonium recycle. This type of fuel cycle change could be taken as economically driven perturbation of the reference case.
Acceptance Limit AL1.4.1: The robustness index $RI \leq 1$ for all the critical economic indicators.

This acceptance limit implies:

- The INS needs to be flexible enough for all the critical economic indicators selected by the assessor.

- In the range of variation of the more critical economic indicators, the assessor doesn’t need to be unnecessary conservative in order to avoid an unnecessary INS rejection.

- Each economic indicator will be perturbed separately (isolated from the other critical indicators).

- Very conservative values could only be asked for in the case, when a very robust INS is the objective of the assessor.
Chapter 4
REFERENCES


[14] Case study of the feasibility of small and medium nuclear power plants in Egypt. IAEA Tecdoc 739, April 1994, Vienna.


[27] IAEA. Thermodynamic and economic evaluation of co-production plants for electricity and potable water. IAEA TECDOC 942. 1997


ANNEX A: Numerical Example

Chapter A.1
Case Description

The hypothetical assessor using the INPRO methodology in the numerical example will be an expert interested in performing a fast evaluation about the potential competitiveness of a single plant with Small and Medium size Reactors (SMR) to start to operate in the year 2010. The country is a small developing country with a deregulated electrical market for base load generation, without any legislation that promotes some options against others, credits or taxes for chemical pollutant or greenhouse gases savings or emissions, or radioactive releases of non-nuclear plants. The nuclear power plant owner needs to make his own economic previsions for back-end and decommissioning, but assuming international standards (the state will be in charge of doing the proper arrangements to achieve these standards).

The country does not have significant resources of uranium or fossil fuels.

The entire example and the assumptions will be arbitrary and only focused in computing a complete numerical example, without any link to a real situation.

A.1.1 Data used:

Usually a substantial amount of data is needed to specify the situation of electricity supply in a given country. But to simplify the example, it will be assumed that the peak and base loads are proportional to the total annual electricity consumption. This assumption should not be considered to be generally valid, but using it in the example, significantly reduces the amount of data required.

Electrical Situation in the country at year 2000:

- Annual Electrical consumption: 40000 GWh/Year
- Total Installed Power: 6000 MWe
- Average Power in the Base Load: 3000 MWe
- Maximum Power of New Power Plant recently installed: 300 MWe
- Average Electricity Growth/Year: 4%/Year
Chapter A.2.
Assessment Steps

A.2.1. Electricity Scenarios

Interested in evaluation of his own country, the expert is not interested in a generic evaluation, so the expert wants to easily determine a scenario using data specific for his country. As the electrical market is deregulated, he will use practical criteria used by investors under real market conditions.

With 4% of electricity growth per year, a very simple analytical model will be used. Assuming that the energy growth will keep a constant load variation curve and growth per year: the additions of base load generation and peak load generation could be directly calculated:

\[
\text{Year}_J \times \text{Power}_{MWe} = \text{Year}_0 \times (1 + g)^{\text{Year}_J} (1)
\]

\[
\text{Year}_J \times \text{PowerAdd}_{MWe} = \text{Power}_{MWe} \times (1 + g)^{\text{Year}_J-1} \times g (2)
\]

Where:

\(g\) is the electricity growth per year (\(g=0.04\) in our example).

\(\text{Year}_J\) is the number of the year in the future, taking as reference the \(\text{Year}_0\) (2000).

\(\text{Power}_{MWe}\) is the installed peak power or power in the base load.

\(\text{PowerAdd}_{MWe}\) is the new power installed each year in the peak or the base load.

For base load generation \(\text{Power}_{MWe} = 3000\) MWe, and in the first year (2001) a new \(\text{PowerAdd}_{MWe} = 124\) MWe is needed, in the second year 124.8 MWe, in the third 129.8 MWe and in the fourth 135.0 MWe.

Using the formula (2) of Annex B, the accumulated additional power installed \(\Delta \text{PowerAdd}_{MWe}\) in a number of \(\Delta J\) years in the time period that starts with the year \(\text{Year}_J\) is:

\[
\Delta \text{PowerAdd}_{MWe} = \text{Power}_{MWe} \times (1 + g)^{\text{Year}_J-1} \times g \times \left(\frac{1-(1+g)^{\Delta J}}{1-(1+g)}\right) (3)
\]

To define the scenario for energy supply the assessor will assume:
1. Criteria used in the economic decision making process: a given new unit should constitute no more than 10% of the total system capacity [A1]. Thus, the maximum power needs to be lower than 600 MWe in year 2000 and 890 MWe in year 2010. In a deregulated electrical system the investor installs the cheapest option in order to increase revenues. Thus, units smaller than 890 MWe could be installed, if the option is the cheapest compared with the alternatives in leveled values using the market discount rate of the energy sector. Units larger than that will not be installed even if the units are the cheapest.

2. Investment rules: In a deregulated system with private investors the capital is invested by the owners using different ways of rising funds in the capital market. The company needs to offer high enough a profit to be attractive, depending on the risk of each investment. Figures of merit for rising funds in the capital market [A2] will be the Internal Return Rate (IRR) and the Return on Investment (ROI), in order to be logically independent from the net present value.

3. Expansion rate needs: With a given historical expansion rate of electricity demand the assessor could define another power limit taking into account the maximum power that could be installed assuming that the power plant needs to be sufficient to satisfy the growth rate of the base load generation for some time period. To calculate such a value, the growth rate needs to be fixed. As the assessor is not interested in other scenarios than the presented situation, he could extrapolate that the historical expansion rate will stay constant for the next years. With the expansion rate and the period of time that he wants to cover for base load generation, he could fix this limit for the power output. Using the period time of 1 to 4 year as a minimum and maximum time limit\(^2\), the new power required for the electrical grid as base load generation starting at 2010 becomes 170 to 725 MWe.

4. Without significant resources for fossil fuels, or local resources or an uranium industry for nuclear fuel supply, the only option is to get all of them from the international market, using for the time evolution published data about future trends in different scenarios. Indigenous nuclear fuel cycles are not in the scope of the assessor because he is interested only in evaluating the power potential of a nuclear option as an investment opportunity, without additional strategic criteria. Only options with real potential to be taken as commodities will be used as fuel, excluding fuels that are not easy to be transported (like coal or natural gas without access to large gas pipe lines).

Table A1 shows a resume of the electricity scenarios for the economic assessment.

\(^2\) The time limits of 1 and 4 years are based on the following: one year is the shortest time period for significant base load addition and four years is, presently, the minimum conceivable construction time for a nuclear power plant.
**Table A1. Electricity Scenario Summary.**

<table>
<thead>
<tr>
<th>Scenario Conditions</th>
<th>Criteria and Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic criteria</td>
<td>Cheapest option will be selected for year 2010</td>
</tr>
<tr>
<td>Technical Constraints</td>
<td>Power limited to 10% of total grid power output: Power lower than 890 MWe</td>
</tr>
<tr>
<td>Investment Rules</td>
<td>Attractive IRR</td>
</tr>
<tr>
<td></td>
<td>Attractive ROI</td>
</tr>
<tr>
<td>Growth Constraints</td>
<td>Power limited by annual new power requirement range: 1 to 4 years range: 170 to 725 MWe</td>
</tr>
<tr>
<td>Fuels availability</td>
<td>Fuels obtained only from the international markets</td>
</tr>
</tbody>
</table>

### A.2.2. Energy Options Alternatives

As was defined in the case description (Chapter A1), the assessor is interested in the base load generation, so the load factor will be considered basically as a the availability factor, because it will be assumed that the grid will buy all the electricity produced.

Without access to local fossil fuel, gas pipelines, or local nuclear fuel, from the international market LWR and HWR OT nuclear fuel, liquefied natural gas (LNG) or Diesel (D) are available. Diesel fuel usually is not considered for base load generation in many developed countries [A3][A4], but is still an important player in many small developing countries.

In a deregulated electricity supply system, and without incentives to encourage any alternative, no other options will be included, assuming that there is no local potential for base load generation in renewable energies, like hydro and intermittent renewables such as solar or wind.

For the available fuels, the alternatives are limited to: SMR nuclear power plants (NPP), Piston Engines (PE), Gas Turbines (GT) and Combined Cycle Gas Turbines (CCGT). So, even without specific data about the generation plants in the grid, it could be supposed, with little uncertainty that all these fossil fuel machines could be found in the electricity network.

Then, as discussed in Section 2.1, using fuel availability as a screening tool to select the energy supply alternatives, PE, GT and CCGT need to be considered. As the assessor is specially interested in a SMR, this type of NPP will be considered too.
A more careful selection needs to be done, in order to check the consistency between the power scenario and the technical limits of each alternative.

A lot of technical data has been published for SMR, but complete sets of published economic data are very unusual. So special care needs to be taken for the availability of economic data and the maturity level thereof. As the most frequent installed reactor type is the PWR, and 1/5 of new additions are HWRs, a SMR PWR will be used, together with a SMR HWR as candidates for NPP evaluation.

The biggest PE is about 40 MWe, but it is not very usual to find PE running with diesel with more than 10 MWe. Usually large PE run with heavy fuel if it is available and inexpensive for some local reasons [A5]. If the energy growth is approximately 150 MWe per year, 10MWe per PE is too small for base load generation. Then the grid size is too large for a PE because for simplicity no multi units will be used in the example.

Both CCGT and GT technologies have a lot of state of the art machines in the range of 150 MWe for base load generation, and then units around this power level will be used for both D and LNG.

The energy options summary is shown in Table A2

<table>
<thead>
<tr>
<th>Option Number</th>
<th>Energy Type</th>
<th>Technology</th>
<th>Fuel</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Nuclear</td>
<td>SMR PWR</td>
<td>Enriched Uranium</td>
</tr>
<tr>
<td>2</td>
<td>Nuclear</td>
<td>SMR HWR</td>
<td>Natural Uranium</td>
</tr>
<tr>
<td>3</td>
<td>Gas</td>
<td>GT</td>
<td>LNG - Diesel</td>
</tr>
<tr>
<td>4</td>
<td>Gas</td>
<td>CCGT</td>
<td>LNG - Diesel</td>
</tr>
</tbody>
</table>

Assuming that the additional energy need of four years could be installed in a single machine (a rather challenging assumption), the maximum power installed for base load will be 725 MWe between the years 2010 to 2013. This is close to the power of many innovative reactors, like AP600 of Westinghouse, CANDU-6 of Canada and WWER-640 from Russia.

### A.2.3 Technical assumptions.

In nuclear technology there are a lot of innovative systems proposed in the power range of 600 MWe. But for the scope of the assessor, interested in an economic power option ready to be deployed, in order to introduce nuclear power in his electrical system, advanced
concepts with evolutionary designs will be used as nuclear, instead of innovative designs [A6].

As the assessor is in a deregulated electrical system, he will use a commercial oriented approach trying to reduce the cost of the nuclear system. To reduce costs the assessor will use the international market to supply a fully commercially available OT fuel cycle, because he is not interested in a more strategic approach like reduction of imports or energy independence.

1. Complete Energy Systems Data Sources:

a. Nuclear Fuel Cycle: The assessor will buy from the international market the different elements of the OT fuel cycle. A very recent update of present commercial standard is the OECD report [A7] about the economics of nuclear fuel cycles. It could be applicable, because the assessor is interested in this INPRO evaluation as a generic evaluation rather than in a fully commercial study. So the data and steps of this reference, for LWR and HWR OT fuel cycle will be take as data for his assessment. As the data will be taken from international, fully commercially oriented plants, their specific output is not relevant because data that suppose to be in a full-scale economy will be used. The price of conversion and fuel manufacturing has been relative constant the last 20 years, but enrichment has been suffering fast price changes during recent years. Future prices will depend on the scale of nuclear energy deployment, basically on the quantity of funds that will be needed to be raised in the capital market.

At present there are two possible scenarios: a close to present situation with stagnation for 50 years, or a significant increase after 2010. Due to the complex feedback between prices and time in both scenarios, a more simple approach will be used, keeping constant a base value and upper and lower levels market limits, extracted from open literature focused on economic future of trends of water cooled fuel cycles [A7][A9]. As could be seen in Table A.3, the ranges finally used will be those with the lower variation, and the shortest time value.
Table A.3. Nuclear Fuel Cycle Data

(References [A7] and [A9] both used US 1991 price values).

<table>
<thead>
<tr>
<th>Stage</th>
<th>Time (Years)</th>
<th>Published Time (years)</th>
<th>Base value</th>
<th>Range value</th>
<th>Unit</th>
<th>Published Range</th>
<th>Losses (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enrichment</td>
<td>.75</td>
<td>1 [A7] .75 [A9]</td>
<td>110 $/SWU</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CANDU Fabrication</td>
<td>.8</td>
<td>.8 [A7]</td>
<td>65$/Kg</td>
<td>- Kg U</td>
<td>-</td>
<td>0.5 [A7]</td>
<td></td>
</tr>
</tbody>
</table>

b. Reactor Specification: Using the technical constraints of Table A.1, with the nuclear energy options of Table A.2, to define the INS, the assessor needs to define the reactor reference plants. For LWR technology, the only mature technologies for the scope are the VVER 640 and AP600, and the second will be selected because a lot of commercial data has been published. The main economic data of AP600 will be taken from Ref. [A8], and technical data from [A11]. For HWR, Canadian and Indian designs could be used. Detailed data has been published in a recent OECD report from Canada [A3] (for a twin unit, and for simplicity it will be assumed that the cost will be directly proportional) for a CANDU 6 plant, technical data for the plant will be taken from [A11]. The data of the Indian HWR with 455 MWe are not applicable for the example, because they are strictly build on a local (national) basis without export experience, contrary to CANDU 6 that has been exported to several countries (Argentina, China, Romania and South Korea). These reactor options are compatible with the growth constraints of Table A.1. Tables A.4 and A.5 summarize the relevant data used in the example for both reactor types.
### Table A.4. PWR Reactor Specification

*(price for US year 1990 [A8]*)

<table>
<thead>
<tr>
<th>Item</th>
<th>Data</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactor Type</td>
<td>AP600</td>
<td></td>
</tr>
<tr>
<td>Thermal Output</td>
<td>1940 MWth</td>
<td>[A11]</td>
</tr>
<tr>
<td>Net Electrical Output</td>
<td>600 MWe</td>
<td>[A11]</td>
</tr>
<tr>
<td>Load Factor</td>
<td>90 %</td>
<td>[A11]</td>
</tr>
<tr>
<td>Life of Plant (*)</td>
<td>60 years</td>
<td>[A11]</td>
</tr>
<tr>
<td>Fuel Burn up</td>
<td>40000 MWd/THM</td>
<td>[A11]</td>
</tr>
<tr>
<td>Fuel Enrichment</td>
<td>3.55 %</td>
<td>[A11]</td>
</tr>
<tr>
<td>Initial Fuel Enrichment</td>
<td>2.0/3.0 %</td>
<td>[A11]</td>
</tr>
<tr>
<td>Power Density</td>
<td>28.89 KWth/KgU</td>
<td>[A11]</td>
</tr>
<tr>
<td>Overnight Cost</td>
<td>1145 $/KWe</td>
<td>[A8]</td>
</tr>
<tr>
<td>Contingency Cost</td>
<td>225 $/KWe</td>
<td>[A8]</td>
</tr>
<tr>
<td>Owners Costs</td>
<td>137 $/KWe</td>
<td>[A8]</td>
</tr>
<tr>
<td>FOAK Costs</td>
<td>43 $/KWe</td>
<td>[A8]</td>
</tr>
<tr>
<td>IDC (**)</td>
<td>396 $/KW</td>
<td>[A8]</td>
</tr>
<tr>
<td>Fixed O&amp;M Costs</td>
<td>49 $/KWe</td>
<td>[A8]</td>
</tr>
<tr>
<td>Variable O&amp;M Costs</td>
<td>0.9 mills/KWh</td>
<td>[A8]</td>
</tr>
<tr>
<td>Decommissioning</td>
<td>1 mills/KWh</td>
<td>[A8]</td>
</tr>
</tbody>
</table>

(*) Plant design objective of 60 years without reactor vessel replacement.

(**) The reference does not specify the discount rate used to obtain the IDC, only detailed construction time of 4 years, but comparing similar Over Night costs and capital amortization between cost of [A11] and [A8], it could be supposed that the IDC has been calculated with a discount rate of 6.2%/year as used in [A11].
**Table A.5. HWR Reactor Specification (price for US year 1996 [A3])**

<table>
<thead>
<tr>
<th>Reactor Type</th>
<th>CANDU 6</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Item</td>
<td>Data</td>
<td>Reference</td>
</tr>
<tr>
<td>Thermal Output</td>
<td>2158 MWth</td>
<td>[A11]</td>
</tr>
<tr>
<td>Net Electrical Output</td>
<td>666 MWe</td>
<td>[A11]</td>
</tr>
<tr>
<td>Load Factor</td>
<td>80 %</td>
<td>[A3]</td>
</tr>
<tr>
<td>Life of Plant</td>
<td>35 years (*)</td>
<td>[A11]</td>
</tr>
<tr>
<td>Fuel Burn up</td>
<td>7500 MWd/THM</td>
<td>[A11]</td>
</tr>
<tr>
<td>Fuel Enrichment</td>
<td>Natural Uranium</td>
<td>[A6]</td>
</tr>
<tr>
<td>Initial Fuel Enrichment</td>
<td>Natural Uranium</td>
<td>[A11]</td>
</tr>
<tr>
<td>Power Density</td>
<td>23.5 KWth/KgU</td>
<td>[A11]</td>
</tr>
<tr>
<td>Overnight Cost</td>
<td>1697 $/KWe</td>
<td>[A3]</td>
</tr>
<tr>
<td>Contingency Cost</td>
<td>85 $/KWe</td>
<td>[A3]</td>
</tr>
<tr>
<td>Owners Costs</td>
<td>0 $/KWe</td>
<td>[A3]**</td>
</tr>
<tr>
<td>FOAK Costs</td>
<td>0 $/KWe</td>
<td>[A3]**</td>
</tr>
<tr>
<td>Back fitting Costs</td>
<td>75 $/KWe</td>
<td>[A3]**</td>
</tr>
<tr>
<td>% of $ Investment/year</td>
<td>1.1/6.1/13.2/22.3/28.2/21.7/7.3</td>
<td>[A3]</td>
</tr>
<tr>
<td>Fixed O&amp;M Costs</td>
<td>54.94 $/KWe</td>
<td>[A3]</td>
</tr>
<tr>
<td>Variable O&amp;M Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Decommissioning</td>
<td>11 $/KWe</td>
<td>[A3]</td>
</tr>
</tbody>
</table>

(*) Pressure tube replacement is not required in new CANDU 6 plants for 35 years [A11]

(**) These costs are included in the overnight construction cost.

(***) Life extension is for a further 35 years for a total plant life of 70 years.
c. Fossil Fuel Alternatives: Usually two OECD countries fully use LNG as fuel for their gas fired plants and published their evaluation in open literature [A6], one is Japan and the other is Republic of Korea. The problem in LNG gas pricing is that there are a lot of uncertainties for the medium and long-term price, depending if LNG will be deployed on a significant larger scale in order to build an alternative to natural gas transported by pipelines, or whether it will remain as a particular situation for some specific cases. LNG market is also coupled with diesel – oil price fluctuation, but the reality has proven that the link between oil and gas price has been weak, and likely to become weaker. So two scenarios will be used for LNG price evolution. One scenario keeps the present price constant in time at present values in Japan and Korea. In this first scenario future more expensive gas production will be balanced by improved scale economy in LNG technology, technology learning and market liberalization that usually tends to reduce price by competition. The second scenario predicts a modest annual escalation rate of 1% per cent, this scenario is taken as a limit for the weakness of constant annual escalation, because a rate of 2.3% over a 30 year period results in doubling of energy price and for fuels such increase would result in substitute energy sources being called into greater use and competing on price.

**Table A.6. LNG Cycle Data (price for US year 1996 [A3])**

<table>
<thead>
<tr>
<th>Item</th>
<th>Gas Price</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower Limit Gas price increase</td>
<td>0% /year</td>
<td>KR-G [A3]</td>
</tr>
<tr>
<td>Upper Limit Gas price increase</td>
<td>1% /year</td>
<td>This work</td>
</tr>
</tbody>
</table>
d. GT and CCGT Specifications: Fossil fuel plants usually are developed in order to minimize the capital, so usually new power plants additions range in the lower limit of growth constraints of Table A.1, 170 MWe. The bigger feasible alternative theoretically will be 725 MWe, in agreement with the upper limit of growth constraints and technical constraints of Table A.1, but there is no single engine with such power, so the bigger GT and CCGT single machines will be used. Using published GT and CCGT handbook data [A10], there are two GT with power around the 170 MWe, Siemens V94.2 (159 MWe) and Westinghouse 501F (177MWe). The Siemens machines will be used for the example, because is the only company that additionally has a large single engine (one GT and one steam turbine) CCGT, the GUD 1S.94.3 (380 MWe), and then both GT and CCGT could be calculated using data supplied by the same company. The tables A7 and A8 show the data of the fossil fuel plants.
Table A.7. GT Power Plant Specification

*(price for US year 1997 [A10] or other date is specified)*

<table>
<thead>
<tr>
<th>Item</th>
<th>Data</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>GT Model</td>
<td>Siemens V84.3</td>
<td></td>
</tr>
<tr>
<td>Thermal Output</td>
<td>474 MWth</td>
<td>[A10]</td>
</tr>
<tr>
<td>Net Electrical Output</td>
<td>180 MWe</td>
<td>[A10]</td>
</tr>
<tr>
<td>Load Factor</td>
<td>75%</td>
<td>[A3]</td>
</tr>
<tr>
<td>Life of Plant</td>
<td>40 years</td>
<td>[A3]</td>
</tr>
<tr>
<td>LHV Efficiency</td>
<td>38 %</td>
<td>[A10]</td>
</tr>
<tr>
<td>Overnight Cost</td>
<td>200 $/KWe</td>
<td>[A10]</td>
</tr>
<tr>
<td>Contingency Cost (*)</td>
<td>20$/KWe (1991 US)</td>
<td>[A12]</td>
</tr>
<tr>
<td>FOAK Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Lead Time (***</td>
<td>2 years</td>
<td>[A12]</td>
</tr>
<tr>
<td>Fixed O&amp;M Costs(****)</td>
<td></td>
<td>[A12]</td>
</tr>
<tr>
<td>Variable O&amp;M Costs</td>
<td>5 $/MWh (1991 US)</td>
<td>[A12]</td>
</tr>
<tr>
<td>Decommissioning</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(*) Reference [A12] recommends 10% of contingency margin for all type of fossil fuel plants, this is consistent with the data provided for some developing countries in [A3].

(**) Reference [A10] recommended additional 60% to 100% additional engine costs, so 60% will be used in this study, and the final investment value (380 $/KWe) is rather consistent with investment costs given in reference [A12] (400 $/KWe).

(***) Reference [A12] recommended 2 years of construction lead-time, assuming a constant cash flow distribution each year.

(****) The data supplier has assumed that the variable cost is the main O&M cost and has incorporated the fixed O&M costs in the variable costs by assuming an effective load factor.
Table A.8. CCGT Power Plant Specification

(price for US year 1997 [A10] or other date is specified)

<table>
<thead>
<tr>
<th>Item</th>
<th>Data</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT Model</td>
<td>Siemens GUD 1S.94.3</td>
<td></td>
</tr>
<tr>
<td>Thermal Output</td>
<td>650 MWth</td>
<td>[A10]</td>
</tr>
<tr>
<td>Net Electrical Output</td>
<td>380 MWe</td>
<td>[A10]</td>
</tr>
<tr>
<td>Load Factor</td>
<td>75%</td>
<td>[A3]</td>
</tr>
<tr>
<td>Life of Plant</td>
<td>40 years</td>
<td>[A3]</td>
</tr>
<tr>
<td>LHV Efficiency</td>
<td>58 %</td>
<td>[A10]</td>
</tr>
<tr>
<td>Overnight Cost</td>
<td>376 $/KWe</td>
<td>[A10]</td>
</tr>
<tr>
<td>Contingency Cost (*)</td>
<td>38$/KWe (1991 US)</td>
<td>[A12]</td>
</tr>
<tr>
<td>Owners Costs (**)</td>
<td>380 $/KWe</td>
<td>[A10]</td>
</tr>
<tr>
<td>FOAK Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Lead Time (***)</td>
<td>3 years</td>
<td>[A12]</td>
</tr>
<tr>
<td>Fixed O&amp;M Costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Variable O&amp;M Costs</td>
<td>6 $/MWh (1991 US)</td>
<td>[A12]</td>
</tr>
<tr>
<td>Decommissioning</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(*) Reference [A12] recommends 10% of contingency margin for all type of fossil fuel plants.

(**) Reference [A10] recommended additional condenser, cooling tower, transformer and switchgear, balance of plant, budget services and labor with a total value of 380 $/KWe.

(***) Reference [A12] recommended 3 years of construction lead-time, assuming a constant cash flow distribution each year.

2. Facilities Specifications: Each facility included in the INS definition need to be specified in two main categories:

a. Facility specification relevant for economic assessment: like output capacity, efficiencies and plant specifications. A NPP requires net electrical power, net efficiency, core power density (in KW/Heavy Metal load), time between refueling, fraction of core
reload and burn up. An enrichment plant requires, the enrichment services costs, cascade efficiency and tail concentration. Table A.9 shows the data used in the example.

**Table A.9. Nuclear Fuel Cycle Data Facilities specifications**

*(References [A7] and [A9] both used US 1991 price values).*

<table>
<thead>
<tr>
<th>Stage</th>
<th>Items</th>
</tr>
</thead>
<tbody>
<tr>
<td>Uranium Purchase</td>
<td>0 % [A7] losses</td>
</tr>
<tr>
<td>Conversion</td>
<td>0.5 % [A7] losses</td>
</tr>
<tr>
<td>Enrichment</td>
<td>0 % [A7] losses - tail assay 0.25% [A9] Feed assay 0.711% [A9]</td>
</tr>
<tr>
<td>Fabrication</td>
<td>1.0 % [A7] losses</td>
</tr>
<tr>
<td>CANDU Fabrication</td>
<td>0.5 % [A7] losses</td>
</tr>
</tbody>
</table>

**A.2.4 Economic assumptions**

To perform the economic assessment, many issues need to be addressed:

a. Fiscal regimes change widely from country to country, and national, regional and local conditions could change substantially. So the calculation will be carried out without income and profit taxes because such taxes do not affect the relative competitiveness [A8]. Taxes on fuel, emissions and plant specific taxes that may differ from plant to plant are included in the cost if they are applicable.

b. Cost element used in calculation need to be expressed in constant monetary term, as it is generally accepted. Even considering that prices used in the tables are referred to different dates, for simplicity in the calculation it will be assumed that the values are in dollars in the mid of year 2000. The data correction for a single common time does not introduce any significant change (all data are in a small time period).

c. To calculate the LLC or LUEC, the amortization time will be the lifecycle of Table A.4, A.5, A.7 and A.8. Usually comparative methods used a similar load factor for base load generation [A3][A4], but present standard of PWR load factor its significant higher than other fossil fuel energy [A13]. As these differences were produced by technical reasons and the design has several specific design feature that’s keeps this load factor advantage, the load factor claimed by the designers and shown in Table A.4 and A.5 will be used for nuclear reactors. For fossil fuel the load factor used will be the classical load factors achieved by such technologies, as could be seen in Table A.7 and A.8.
d. Proper back fitting need to be considered, specially for technologies with short time between major refurbishment, like GT and CCGT, but unfortunately there is a clear lack of consistence on the values published in comparative assessment [A3][A4]. For the same fossil fuel technology some countries calculate up to 35% of additional costs in backfitting of CCGT, but many others used 0% of backfitting costs. It could be claimed that probably some investment costs include backfitting cost because it is as a contract alternative already included, but in that case the value depends on the discount rate, and it couldn’t be properly taken into account by the values shown in reports. For the technical point of view GT and CCGT requires major refurbishment particularly the firsts rows of blades of the turbine section, together with bearings change and combustion chamber maintenance. All these major refurbishment are very expensive and have not been considered in many comparative studies. Due to the lack of available sources on backfitting costs for GT and CCGT, they will not be considering in the assessment of this example.

A.2.5 Cost coverage and costing basis

Cost data inconsistency is a central issue when the assessor is combining different types of technologies. To analyze if data given for the technical assumptions steps are complete or not, some references [A3][A14] used a comprehensive list of the factors included in the cost comparison.

This type of table could be used as check lists to indicate if the cost coverage has properly been taken into account.

It is important to stress that each item has been properly included only if the value has been specified in a given table, with a proper reference and specifying the time when each cost has been determined. Then the item could be positively checked and verified that each variable is OK.

For the example, a complete checklist could be seen in Tables A.10 and A.11 for the four energy alternatives specified in Table A.2.
Table A.10. Plant Cost Coverage Check List.

<table>
<thead>
<tr>
<th>Item</th>
<th>SMR PWR</th>
<th>SMR HWR</th>
<th>GT</th>
<th>CCGT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Table in the report</td>
<td>Ref</td>
<td>Time</td>
<td>Table in the report</td>
</tr>
<tr>
<td>Owner Costs</td>
<td>A.4</td>
<td>A8 1990</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>FOAK Costs</td>
<td>A.4</td>
<td>A8 1990</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Back Fitting Costs</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>A.5</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>A.4</td>
<td>A8 1990</td>
<td>A.5</td>
<td>A3 1996</td>
</tr>
<tr>
<td>Decommissioning</td>
<td>A.4</td>
<td>A8 1990</td>
<td>A.5</td>
<td>A3 1996</td>
</tr>
</tbody>
</table>

(*) Reference [A8] includes the IDC and not the detailed cash flow and the discount rate used. By comparing published values between [A11] and [A8], a discount rate of 6.2%/year could be assumed to compute the IDC value.

(**) Reference [A12] only specifies the construction time span, without explanation about the detailed cash flow.

(***) Costs calculation will be done in the middle of year 2000 prices
<table>
<thead>
<tr>
<th>Item</th>
<th>SMR PWR</th>
<th>SMR HWR</th>
<th>GT</th>
<th>CCGT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Table in the report</td>
<td>Ref</td>
<td>Time</td>
<td>Table in the report</td>
</tr>
<tr>
<td>Enrichment Value-Time-Losses</td>
<td>A.3</td>
<td>A7 &amp; A9</td>
<td>1991</td>
<td>NA</td>
</tr>
<tr>
<td>Natural Gas Fuel Price</td>
<td></td>
<td></td>
<td></td>
<td>A.6</td>
</tr>
<tr>
<td>Natural Gas Fuel Price Increase</td>
<td></td>
<td></td>
<td></td>
<td>A.6</td>
</tr>
</tbody>
</table>
For the values shown in Table A10, it could be easily seen that many items are completely described for all the energy alternatives. Only three items need some clarification.

FOAK Costs have been detailed only in the SMR PWR case without values for SMR HWR or GT and CCGT. In the SMR HWR the values taken from reference [A3] specify that the cost given for CANDU 6 plant has been taken from a commercial ordered plant (Table 2 of Ref. [A3]), and as many CANDU 6 plant have been recently built in South Korea and China, near zero FOAK costs is a credible value. Both GT and CCGT V94.3 and GUD 1S.94.3 are standard equipment and thus in full nth of a kind production scale, so there are negligible FOAK costs for this units too. Therefore FOAK will be taken as zero for fossil fuel options.

Back Fitting costs has been detailed only for SMR HWR, without values for SMR PWR or GT and CCGT. According to Ref. [A11] there is a large water gap between the core barrel and pressure vessel and SG tube material assures that there are no special back fitting costs concerns for the expected reactor life, thus, back fitting costs for SMR PWR could be assumed close to zero. The zero GT and CCGT back fitting costs are not credible at all, because a Bryton technology requires significant back fitting investment particularly for blade replacement, and some components in the hot zone like inlet guide vanes or combustion chamber elements. Unfortunately few published data are available about such costs, and specially the values applicable to V94.3 and 1S.94.3. Zero will be used due to the lack of data, and because the same consideration is used in other well known reports like [A3][A4] and [A14].

Construction cash flow has been detailed only for SMR HWR, SMR PWR only shows the IDC at 6.2%/year discount rate (obtained by comparison of values in [A11] and [A8]), and no IDC or cash flow for V94.3 and 1S.94.3 are available.

For SMR PWR the IDC could be calculated, at the discount rate selected by the assessor, applying the model of the effective investment time, according to Table B.2 of Annex B. Using data from Table A.4, the IDC of 396 $/KWe at 6.2% discount rate, and a total investment of 1550 $/KWe (adding the FOAK, owners and contingency costs), the effective investment time using formula (22) of Annex B is 3.8 years. Then the cash flow is modeled as a single payment advanced of 3.8 years.

For GT and CCGT, Tables A.7 and A.8 do not include the cash flow payment, but include the construction time, and according to Table B.2 of Annex B, in this case the cash flow could be replaced with a single delay at middle of the construction time, using formula (19) of Annex B. Table A.7 and A.8 specify a construction time of 2 and 3 years for GT and CCGT respectively, and then the cash flow are modeled as a single delay payment of 1 and 1.5 years.

For O&M costs, there are no fixed costs for GT and CCGT, and no variable costs for SMR HWR. In detailed reports like [A3][A14] there are similar power plants with the same assumptions, and it could be taken as a reasonable approximation for base load generation at high load factor due to the technical differences between the technologies. Both GT and
CCGT O&M costs are mainly related with the hours in operation at full power. Then the lack of values will be taken as zero due to the small effect in the final total O&M costs.

There is no decommissioning cost for GT and CCGT in Table A.7 and A.8, and this assumptions could be found in reports like [A3][A14] and [A4]. This is not because there are no expenses for decommissioning, but because the technologies of GT and CCGT requires relative small decommissioning cost and for very large time delay according with the plant life (40 years for each) the leveled back fitting cost is negligible. Then back fitting cost will be considered zero for GT and CCGT.

Including all this corrections into the tables A.4, A.5, A.7 and A.8, the consolidated and consistent data set for this annex could be seen in Table A.12.

For the values shown in the checklist Table A.11, the original data in Table A.3 and A.6 are complete and could be used without problems in this annex.
### Table A.12. Complete Power Plant Cost Data

<table>
<thead>
<tr>
<th>Energy Option</th>
<th>SMR – PWR</th>
<th>SMR – HWR</th>
<th>GT</th>
<th>CCGT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant</td>
<td>AP600</td>
<td>CANDU6</td>
<td>V84.3</td>
<td>GUD 1S.94.3</td>
</tr>
<tr>
<td>Item</td>
<td>Data Ref.</td>
<td>Data Ref.</td>
<td>Data Ref.</td>
<td>Data Ref.</td>
</tr>
<tr>
<td>Initial Fuel Enrichment</td>
<td>2.0/3.0 % [A11]</td>
<td>Natural Uranium [A11]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Back Fitting [$/KWe]</td>
<td>0 This section</td>
<td>75 $/KWe [A3]</td>
<td>0 This section</td>
<td>0 This section</td>
</tr>
<tr>
<td>Cash Flow [years]</td>
<td>3.8 yr delay This section</td>
<td>1.1/6.1/13.2/22.3/28.2/21.7/7.3 [A3]</td>
<td>1 yr delay This section</td>
<td>1.5 yr delay This section</td>
</tr>
<tr>
<td>Fixed O&amp;M Costs [$/KWe]</td>
<td>49 [A8]</td>
<td>54.94 [A3]</td>
<td>0 This section</td>
<td>0 This section</td>
</tr>
<tr>
<td>Variable O&amp;M Costs [mills/KWh]</td>
<td>0.9 [A8]</td>
<td>0 This section</td>
<td>5 1991 [A12]</td>
<td>6 1991 [A12]</td>
</tr>
<tr>
<td>Decommissioning [mills/KWh]</td>
<td>1 [A8]</td>
<td>75 $/KWe [A3]</td>
<td>0 This section</td>
<td>0 This section</td>
</tr>
</tbody>
</table>
A.2.6 Discount and Financial Rates.

In this hypothetical case, the country description and electrical grid has been only broadly described, so there is no real information about the two data required for the discount and financial figures of merit, basically the discount rate \((r)\) and the price that will be used to sell the electricity generated \((PUES)\).

1. Financial data for cost calculation: As in the country description it has been assumed a country with a deregulated electrical system, the discount rate will be taken from reviewed financial rates in developing countries for the energy sector, without additional assumptions about lower values due to some particular governmental policies.

From the reference [A2] it could be found that future discount rates will remain high in developing countries for the electricity sector, and then, and consistent with [A3], a value of 12\% for the discount rate will be used.

2. Financial data for profit calculation: To calculate the price that will be used to sell the electricity, the price – fixing mechanism used in the system needs to be known. Without such data in this example it will be assumed a fixed percentage above the cheapest investment option, in order to reflect some mixture between the cheaper option from new plants, and more expensive old plants.

Then it will be assumed that the average annual selling price \((PUES)\) will be 30\% higher than the cheapest alternative for new plants. If the cheapest alternative will be time dependant, PUES will change in time too.

IRR limit will be taken as 2 \% higher than the discount rate, due to the relative high-risk perception in developing countries [A3], particularly for long-term projects of electricity generation.

The ROI in developed and developing countries has been recently studied by the OECD report Ref. [A21], specially focusing in future trends. In this report there is a compilation of current ROI used in different industries. In this reference the highest level of ROI for the energy sector is 12\%. This value, with 3\% increase for the perceived risk of a nuclear investment, will be taken as the acceptance limit because it is a higher value than the reference, and is compatible with the forecast that in the future developing countries will face a big challenge to rise funds for investment in the energy sector.

The financial data are summarized in Table A.13
Table A.13. Financial Data

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Real Discount Rate ((r))</td>
<td>12</td>
<td>%/year</td>
</tr>
<tr>
<td>Average Annual Electricity Selling Price ((PUES))</td>
<td>(1.3 \times LDC_{cheaper})</td>
<td>mills/KWh ((10^{-3}$\text{}/\text{KWh}))</td>
</tr>
<tr>
<td>Internal Return Rate Limit ((IRR\ Limit))</td>
<td>14</td>
<td>%/year</td>
</tr>
<tr>
<td>Return on Investment Limit ((ROI\ Limit))</td>
<td>15</td>
<td>%/year</td>
</tr>
</tbody>
</table>
Chapter A.3.
INPRO INDICATORS

For the example, all the values and formula used will be referred to Annex B, with detailed comments and explanation if some changes are needed.

A. 3.1. Indicators of UR1.1.

Indicator $IN1.1.1$: $CN$ Single Levelized Discounted Cost of the complete INS ($LDC_{N1}$) or: single Levelized real discounted Unit net generated Electricity plants life total Costs ($LUEC$) for the complete INS, excluding FOAK cost, including external costs and credits when they are fully included in the price setting mechanism, using contingency allowances and a discount rate that reflect the economic decision making investment environment.

As could be seen in Table A.11 and A.12, and Section A.2.5, the direct costs of Table A.11 include direct, owner, contingency and FOAK costs, but the Indicator IN1.1.1 specifically excludes the last one. Only the PWR SMR includes FOAK costs in the overnight costs, therefore to subtract these costs from the overnight investment is correct if it is also subtracted from the interest during construction. To do that it could be assumed that the FOAK cash flow is proportional to the overall investment cash flow, then it could be proportionally subtracted from the IDC. As could be seen in Table A.12, then as the IDC of the PWR SMR could be calculated using the effective investment time, using formula (21) of Annex B, and this time is not affected because the IDC is calculated as a proportional value of the investment already corrected, then the effective investment time stays unchanged after the FOAK cost removal.

For the external costs and credits, the case description in section A.1 clearly defines that the nuclear power plant owner needs to make his own economic previsions for back-end and decommissioning assuming international standards, and there are no credits or taxes for chemical pollutants or greenhouse gases.

Table A.12 specify the decommissioning costs to be used, but still an international value for nuclear back end costs are needed. The Reference [A7] shows a large spread of values for back end costs for LWR OT fuel, ranging from 200 to 960 $/Kg, and Ref. [A9] uses a base value of 400 $/Kg for an even larger range. Then a 400$/Kg (1991 values) charge will be used for SMR PWR at the time of discharge. This is consistent with the usual assumption. For SMR HWR, 73 $/Kg (1991 values) is used in Ref. [A9] for CANDU fuel backend, thus, this value will be taken for SMR HWR reactor as a charge at the time of discharge.

The case description defines that there are no charges or credits for emission or savings for chemical pollutants and greenhouse gases, or radioactive releases of non-nuclear plants.

Then the data changes needed to compute the indicator IN1.1.1 are listed in Table A.14.
Using all the tabulated values, and the formulas of Annex B, all the intermediate values, required to determine $C_N$ or $LUEC_N$ values, could be calculated by using the following definitions given by the case assumptions:

- Base time: $t_0 = 0$ = First commercial full power operation in year 2010 (section A.1.1).

**Indicator IN1.1.1. for SMR PWR**

The fuel cycle data depends on the nuclear reactor type, then for SMR PWR:

- Fuel cycle stages: $N_{stages} = 4$ from Table A.9.
- Enrichment feed in the enrichment plant: $\varepsilon_F = 0.711\%$ for classical OT cycle [A7][A9].
- Enrichment tail in the enrichment plant: $\varepsilon_T = 0.25\%$ for classical OT cycle [A7][A9].

With all these data, the intermediate data included in Table A.15 could be calculated.
<table>
<thead>
<tr>
<th>Intermediate Variable</th>
<th>Value</th>
<th>Units</th>
<th>Formula</th>
<th>Input data in Table</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t_{START}$</td>
<td>-4</td>
<td>years</td>
<td>10b</td>
<td>A.4</td>
</tr>
<tr>
<td>$t_{END}$</td>
<td>59</td>
<td>years</td>
<td>9</td>
<td>A.4</td>
</tr>
<tr>
<td>$L_{hFP}$</td>
<td>73502</td>
<td>hr.</td>
<td>9b</td>
<td>A.4, A.14</td>
</tr>
<tr>
<td>$t_D$</td>
<td>60</td>
<td>years</td>
<td>11b</td>
<td>A.4</td>
</tr>
<tr>
<td>$C_{1DC}$</td>
<td>811</td>
<td>$$/KWe$</td>
<td>22</td>
<td>A.12, A.14</td>
</tr>
<tr>
<td>$LUAC$</td>
<td>32.5</td>
<td>mills/KWh</td>
<td>11c</td>
<td>A.4,A.14,A.15</td>
</tr>
<tr>
<td>$LUOM$</td>
<td>7.1</td>
<td>mills/KWh</td>
<td>12</td>
<td>A.4,A.15</td>
</tr>
<tr>
<td>HM&lt;sub&gt;1&lt;/sub&gt;/HM&lt;sub&gt;FE&lt;/sub&gt;</td>
<td>1.01</td>
<td>1.01</td>
<td>1.01</td>
<td>Kg/Kg</td>
</tr>
<tr>
<td>HM&lt;sub&gt;2&lt;/sub&gt;/HM&lt;sub&gt;FE&lt;/sub&gt;</td>
<td>1.01</td>
<td>1.01</td>
<td>1.01</td>
<td>Kg/Kg</td>
</tr>
<tr>
<td>$F$</td>
<td>3.796</td>
<td>5.965</td>
<td>7.158</td>
<td>Kg/Kg</td>
</tr>
<tr>
<td>$V(\varepsilon_P)$</td>
<td>3.736</td>
<td>3.268</td>
<td>3.068</td>
<td></td>
</tr>
<tr>
<td>$V(\varepsilon_F)$</td>
<td>4.869</td>
<td>4.869</td>
<td>4.869</td>
<td></td>
</tr>
<tr>
<td>$V(\varepsilon_T)$</td>
<td>5.959</td>
<td>5.959</td>
<td>5.959</td>
<td></td>
</tr>
<tr>
<td>SWU</td>
<td>1.915</td>
<td>3.811</td>
<td>4.912</td>
<td>SWU/Kg</td>
</tr>
<tr>
<td>HM&lt;sub&gt;3&lt;/sub&gt;/HM&lt;sub&gt;FE&lt;/sub&gt;</td>
<td>3.834</td>
<td>6.025</td>
<td>7.230</td>
<td>Kg/Kg</td>
</tr>
<tr>
<td>HM&lt;sub&gt;4&lt;/sub&gt;/HM&lt;sub&gt;FE&lt;/sub&gt;</td>
<td>3.834</td>
<td>6.025</td>
<td>7.230</td>
<td>Kg/Kg</td>
</tr>
<tr>
<td>$S/K_{FE}$</td>
<td>787</td>
<td>1166</td>
<td>1381</td>
<td>$$/Kg$</td>
</tr>
<tr>
<td>LUFC</td>
<td>7.5</td>
<td>mills/KWh</td>
<td>16b</td>
<td>A.12,A.15</td>
</tr>
</tbody>
</table>
Then, the indicator value could be obtained by adding $LUAC$, $LUOM$ and $LUFC$ of Table A.15, that gives $LUEC$ according with equation (6d):

$$C_{N-\text{SMR PWR}} = LUEC = 47.14 \text{ mills/KWh}$$

**Indicator IN1.1.1. for SMR HWR**

For SMR HWR, the fuel cycle do not require the uranium enrichment step, then:

- Fuel cycle stages: $N_{\text{stages}} = 3$ from Table A.9.

With all these data, the intermediate data included in Table A.16 could be calculated.

This reactor is the only power plant with a detailed cash flow, so the IDC could be exactly calculated by using formula (10b).

All the intermediate data to calculate the indicator are summarized in Table A.16, assuming that the cost includes the heavy water for start up and for annual heavy water consumption.

Then, the indicator value for SMR HWR could be obtained from $LUEC$ according to equation (6d):

$$C_{N-\text{SMR HWR}} = LUEC = 48.79 \text{ mills/KWh}$$
### Table A.16. Intermediate data calculation of SMR - HWR

<table>
<thead>
<tr>
<th>Intermediate Variable</th>
<th>Value</th>
<th>Units</th>
<th>formula</th>
<th>Input data in table</th>
</tr>
</thead>
<tbody>
<tr>
<td>( t_{\text{START}} )</td>
<td>-6</td>
<td>years</td>
<td>10b</td>
<td>A.5</td>
</tr>
<tr>
<td>( t_{\text{END}} )</td>
<td>34</td>
<td>years</td>
<td>9</td>
<td>A.5</td>
</tr>
<tr>
<td>( Lh_{FP} )</td>
<td>64169</td>
<td>hr.</td>
<td>9b</td>
<td>A.5,A.13</td>
</tr>
<tr>
<td>( t_D )</td>
<td>35</td>
<td>years</td>
<td>11b</td>
<td>A.5</td>
</tr>
<tr>
<td>( CI_{IDC} )</td>
<td>572</td>
<td>$/KWe</td>
<td>10b</td>
<td>A.12,A.14</td>
</tr>
<tr>
<td>( LUAC )</td>
<td>36.86</td>
<td>mills/KWh</td>
<td>11c</td>
<td>A.5,A.14, A.15</td>
</tr>
<tr>
<td>( LUOM )</td>
<td>7.84</td>
<td>mills/KWh</td>
<td>12</td>
<td>A.5,A.15</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>1st Core</th>
<th>Refueling</th>
</tr>
</thead>
<tbody>
<tr>
<td>( HM_1/\text{HM}_F )</td>
<td>1.005</td>
</tr>
<tr>
<td>( HM_2/\text{HM}_F )</td>
<td>1.005</td>
</tr>
<tr>
<td>( HM_3/\text{HM}_F )</td>
<td>1.010</td>
</tr>
<tr>
<td>$/K_F )</td>
<td>138</td>
</tr>
<tr>
<td>( LUFC )</td>
<td>4.10</td>
</tr>
</tbody>
</table>

**Indicator IN1.1.2. for GT and CCGT**

Both GT and CCGT use LNG as fuel, so the same calculation could be performed changing the values used in each plant. All the intermediate data to calculate the indicator are summarized in Table A.17.
Table A.17. Intermediate data calculation of GT and CCGT

<table>
<thead>
<tr>
<th>Intermediate Variable</th>
<th>Value for GT</th>
<th>Value for CCGT</th>
<th>Units</th>
<th>Formula in app. B</th>
<th>Input data in Table</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t_{\text{START}}$</td>
<td>-3</td>
<td>-3</td>
<td>Years</td>
<td>10b</td>
<td>A.7, A.8</td>
</tr>
<tr>
<td>$t_{\text{END}}$</td>
<td>39</td>
<td>39</td>
<td>Years</td>
<td>9</td>
<td>A.7, A.8</td>
</tr>
<tr>
<td>$L_{\text{hFP}}$</td>
<td>60661</td>
<td>60661</td>
<td>hr.</td>
<td>9b</td>
<td>A.7, A.8, A.13</td>
</tr>
<tr>
<td>$t_D$</td>
<td>40</td>
<td>40</td>
<td>Years</td>
<td>11b</td>
<td>A.7, A.8</td>
</tr>
<tr>
<td>$C_{\text{IDC}}$</td>
<td>45.6</td>
<td>147</td>
<td>$$/\text{KWe}$</td>
<td>10b</td>
<td>A.12, A.13</td>
</tr>
<tr>
<td>$L_{\text{UAC}}$</td>
<td>7.02</td>
<td>15.51</td>
<td>mills/KWh</td>
<td>11c</td>
<td>A.12, A.13, A.15</td>
</tr>
<tr>
<td>$L_{\text{UOM}}$</td>
<td>5</td>
<td>6</td>
<td>mills/KWh</td>
<td>12</td>
<td>A.12</td>
</tr>
<tr>
<td>$L_{\text{UFC}}(i=1%)$</td>
<td>49.17</td>
<td>31.94</td>
<td>mills/KWh</td>
<td>41</td>
<td>A.6, A.7, A.8</td>
</tr>
<tr>
<td>$L_{\text{UFC}}(i=0%)$</td>
<td>45.31</td>
<td>29.43</td>
<td>mills/KWh</td>
<td>41b</td>
<td>A.6, A.7, A.8</td>
</tr>
</tbody>
</table>

The indicator for GT and CCGT value could be obtained from $L_{\text{UEC}}$ according to (6d):

\[
C_{A-\text{GT}(i=1\%)} = L_{\text{UEC}} = 61.19 \text{ mills/KWh}
\]

\[
C_{A-\text{CCGT}(i=1\%)} = L_{\text{UEC}} = 53.45 \text{ mills/KWh}
\]

If instead of 1% of a price increase for LNG it is supposed that the price will remain constant for the evaluation time period:

\[
C_{A-\text{GT}(i=0\%)} = L_{\text{UEC}} = 57.33 \text{ mills/KWh}
\]

\[
C_{A-\text{CCGT}(i=0\%)} = L_{\text{UEC}} = 50.95 \text{ mills/KWh}
\]
The difference between the values with or without fuel price increase shows how much influence the hypothesis has on the fuel costs for gas turbine technologies, because the difference could range from 7% to 5% of the total costs.

To be conservative for nuclear, 0% of LNG prices increase is the value that a typical investor will use to evaluate nuclear. This is consistent with the fact that in the nuclear evaluation no price increase has been used for any fuel services or uranium purchase.

Then the final value of the indicators could be summarized in Table A.18

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_{N-SMR:PWR}$</td>
<td>47.14</td>
<td>mills/KWh</td>
</tr>
<tr>
<td>$C_{N-SMR:HWR}$</td>
<td>48.79</td>
<td>mills/KWh</td>
</tr>
<tr>
<td>$C_{A-GT(i=0%)}$</td>
<td>57.33</td>
<td>mills/KWh</td>
</tr>
<tr>
<td>$C_{A-CCGT(i=0%)}$</td>
<td>50.95</td>
<td>mills/KWh</td>
</tr>
</tbody>
</table>

### A.3.2. Indicators of UR1.2.

#### Indicator IN1.2.1.1

$IRR_N$ is defined as the Internal Return Rate (IRR) at the calculated real selling price of the complete INS ($IRR_N$), or more precisely defined: the IRR produced by selling the net electricity produced by the INS at the defined real PUES, excluding costs not included in a price setting mechanism and including costs for confident lifecycle operation, decommissioning and waste treatment.

To calculate the indicator the assessor needs to define the PUES. According to the Table A.13, the PUES needs to be computed by adding 30% to the cheapest LUEC value for the new plants addition. Using data of Table A.18, the cheapest value is 47.14 mills/KWh and with the addition of 30% gives a PUES value of 61.28 mills/KWh. This calculation is summarized in Table A.19.
Table A.19. Final Data for Indicator IN1.2.1.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cheapest LUEC</td>
<td>47.14</td>
<td>mills/KWh</td>
</tr>
<tr>
<td>PUES</td>
<td>61.28</td>
<td>mills/KWh</td>
</tr>
</tbody>
</table>

According to the formula (8) in Annex B, the IRR could be easily computed repeating the LUEC calculation given in Tables A.15, A.16 and A.17 for different discount rates until the LUEC is equal to the PUES of Table A.19.

This calculation gives the IRR values of Table A.20.

Indicator IN1.2.1.2:

$ROI_N$ is defined as the Lifecycle plant average ROI of the complete INS ($ROI_N$), or more precisely defined: the ROI calculated for average lifecycle total plant invested capital and lifecycle average operative incomes produced per average plant.

In all four cases, no price increase has been included during the operative life, and due to the model used to define the $PUES$ this value is constant during the plant life. So the average operative incomes could be calculated as the difference between $PUES$ of Table A.19 and the O&M and Fuel Costs of Tables A.15, A.16 and A.17.

The invested capital is simply the overnight cost multiplied by the net electrical power. As has been explained in Section 2.6, the ROI is calculated dividing the average operative incomes by the total investment.

The ROI calculated with these values could be seen in Table A.20.

Indicator IN1.2.2:

Highest single plant total investment up to commission the reactor in the complete INS.

The total investment is the overnight total cost and the interest during construction multiplied by the electrical power, calculated in millions of US$. The indicator could be calculated from Tables A.15, A.16 and A.17, and is given in Table A.20.
### Table A.20. Indicators of UR 1.2

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indicator IN1.2.1.1.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$IRR_{SMR \ PWR}$</td>
<td>15.68</td>
<td>%/year</td>
</tr>
<tr>
<td>$IRR_{SMR \ HWR}$</td>
<td>15.54</td>
<td>%/year</td>
</tr>
<tr>
<td>$IRR_{A-GT(i=0%)}$</td>
<td>12.32</td>
<td>%/year</td>
</tr>
<tr>
<td>$IRR_{A-CCGT(i=0%)}$</td>
<td>19.54</td>
<td>%/year</td>
</tr>
<tr>
<td>Indicator IN1.2.1.2.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ROI_{SMR \ PWR}$</td>
<td>24.43</td>
<td>%/year</td>
</tr>
<tr>
<td>$ROI_{SMR \ HWR}$</td>
<td>19.4</td>
<td>%/year</td>
</tr>
<tr>
<td>$ROI_{A-GT(i=0%)}$</td>
<td>12.3</td>
<td>%/year</td>
</tr>
<tr>
<td>$ROI_{A-CCGT(i=0%)}$</td>
<td>21.4</td>
<td>%/year</td>
</tr>
<tr>
<td>Indicator IN1.2.2.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$Investment_{SMR \ PWR}$</td>
<td>1391</td>
<td>M$</td>
</tr>
<tr>
<td>$Investment_{SMR \ HWR}$</td>
<td>1565</td>
<td>M$</td>
</tr>
<tr>
<td>$Investment_{A-GT(i=0%)}$</td>
<td>76.6</td>
<td>M$</td>
</tr>
<tr>
<td>$Investment_{A-CCGT(i=0%)}$</td>
<td>358</td>
<td>M$</td>
</tr>
</tbody>
</table>
A.3.3. Indicators of UR1.3

Indicator IN1.3.1:

Level of licensing application to regulatory body required to start the construction of a reference or specific plant or reactor.

Several CANDU6 have been recently constructed, so the design is ready to be build, assuming that the country’s regulatory body will accept the well-known safety standard of Canada. So for CANDU6 this indicator is 1. But, in some countries with a very LWR specific licensing approach, up to now it has been very difficult to license the CANDU reactor.

For AP600 the licensing process with the USNRC reached the final design certification permit, but still the combined licenses of the site characteristics and the design to be approved for construction are required. Dividing the licensing process in several steps like: Preliminary Safety Analysis Report Submission, Final Safety Analysis Report Submission, Combined Licenses Site – Design Presentation Submission, Construction Approval, each step is counted as 0.25 and then the present indicator value is 0.5.

The selected gas turbines are standard equipment that are presently operative all around the world, so there is no question about that in general could be expected any troubles to start the construction of this units. For both the indicator value is 1.

Indicator IN1.3.2:

Time span between the first contract for the plant construction and the start of commercial operation.

This value is shown for the four systems in Tables A.4, A.5, A.7 and A.8, using the definition of construction time or summarized in Table A.10 as construction cash flow.

The indicator in years is summarized in Table A.21.

Indicator IN1.3.3:

Political long term commitment showing support for nuclear power in construction permit, operation support, decommissioning and back end issues, from the investment point of view.
The indicator requires a specification that its out of scope for the present example, because the case definitions is rather independent of a given country condition.

Then for the case the indicator was neglected for both types of NPP, as is shown in Table A.21.

<table>
<thead>
<tr>
<th>Table A.21. Indicators of UR 1.3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Indicator</td>
</tr>
<tr>
<td>Indicator IN1.3.1.</td>
</tr>
<tr>
<td>Licensing(_{\text{SMR PWR}})</td>
</tr>
<tr>
<td>Licensing(_{\text{SMR HWR}})</td>
</tr>
<tr>
<td>Licensing(_{\text{A-GT(i=0%)}})</td>
</tr>
<tr>
<td>Licensing(_{\text{A-CCGT(i=0%)}})</td>
</tr>
<tr>
<td>Indicator IN1.3.2.</td>
</tr>
<tr>
<td>(T_{\text{Cl SMR PWR}})</td>
</tr>
<tr>
<td>(T_{\text{Cl SMR HWR}})</td>
</tr>
<tr>
<td>(T_{\text{Cl A-GT}})</td>
</tr>
<tr>
<td>(T_{\text{Cl A-CCGT}})</td>
</tr>
<tr>
<td>Indicator IN1.3.3.</td>
</tr>
<tr>
<td>Political Commitment</td>
</tr>
</tbody>
</table>

**A.3.3. Indicators of UR1.4**

**Indicator IN1.4.1.**

*Distance of the more critical economic indicator to limit values for other market conditions,* or, *Robustness (Flexibility) index for the more critical economic indicators determined by the assessor, defined as the ratio of perturbed values for different market conditions to tolerable limit values.*

For the example being discussed, the more critical indicators are those that could jeopardize the competitiveness of the NPP with the alternatives. If there is a cheaper alternative installed in the grid, its dispatch would normally be preferred to the nuclear one, either to
keep the price to the consumer low, in the case of a state owned utility, or to maximize the profit to the utility, the case of a privately owned utility.

So a Robustness (Flexibility) Index ($RI$) can be defined on the basis of the ratio of the alternative cost $C_A$ divided by the nuclear cost $C_N$. If the ratio is greater than one, nuclear is cheaper, and if it is smaller, than nuclear is more expensive. This type of indicator (or its inverse) has been used in other studies [A3][A4][A14] and is usually called the relative competitiveness or nuclear/gas cost ratio. To determine the robustness it is necessary to consider changes in this ratio arising from changes in market factors, as discussed in Section 3.3 (Indicators of UR1.4) and Annex B. So the Robustness Index is $\Delta(C_A/C_N)/(C_A/C_N)$ where $\Delta(C_A/C_N)$ is the perturbed value of $C_A/C_N$ for changes of the reference values of the variables that affect $C_A/C_N$. The lower limit for $C_A/C_N$ is 1. I.e., the ratio $C_A/C_N$ should be >1 if nuclear is to be cost competitive with the alternative.

An upper limit could be defined allowing only values of the ratio that are greater than 1.0. This limit may be too restrictive but it could be taken as a way to reduce the risk for an investor making a large capital investment. In the example, the requirement is that $C_A/C_N > 1$, even for the changed market conditions.

The technologies involved in the proposed INS have an excellent track record for base load generation and they are superior to fossil plants. So, the risk of poor technical performance is very low. In a developing country the variables related to problems of funding or plant construction represent a more likely risk for an investor. Another source of risk is the fossil fuel price, particularly because, at present, the LNG infrastructure is developed on a scale that is considerably smaller than that which may develop in the near future (For example significant expansion of LNG infrastructure would be expected to occur if the US moved to using LNG on a large scale). This type of change of scale could raise the price to higher values in some cases, or to lower values in other cases. But it is clear that the price of LNG is subject to uncertainties, and the price may be decoupled from that of other fossil fuels.

So three data ($d_j$) will be selected to estimate the robustness index for deviation from the data used in the reference scenario:

1. $d_1$: $r$: Discount Rate: The financial arrangements for a large investment made over an extended time frame could be quite complex for medium size developing countries, and renegotiations and/or funding delays could increase the discount rate used to increase the attractiveness for investors. It might be expected that discount rates 2% greater than the reference rate might be applied. To bound the robustness index for increases in discount rate, a 3% increase will be used.

2. $d_2$: TCt: Construction Time: The financial problems, together with local problems (technical or non technical) could be related to a construction time delay, that could increase the cost of interest during construction. An increase of 100% of construction time span has been observed in many reactors in several countries. So, a doubling of the construction time will be used to examine the robustness.

3. $d_3$: $$/GJ$: Fossil fuel price: The fossil fuel market is unstable and prices could either increase or decrease. Since we are interested in changes that could negatively affect the
cost-competitiveness of nuclear, the robustness for a cost reduction in the price of LNG will be examined, assuming a 30% price reduction.

Using the worst case data change \((d_j \pm \Delta d_j)\) the indicators (according to formula (27), (28) and (29) in Appendix B) \(C_A/C_N (d_j \pm \Delta d_j)\) were calculated and are shown in Table A.22.

All the procedures and formulas are the same of the previous indicators calculations, because the perturbation does not imply a fuel cycle or reactor technology change.

**Table A.22. Robustness (Flexibility) Index Elements**

<table>
<thead>
<tr>
<th>(D_1: r)</th>
<th>(d_2: T_{Ct})</th>
<th>(d_3: $/GJ):</th>
<th>(C_N)</th>
<th>(C_A)</th>
<th>RI= (C_A/C_N)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMR – PWR</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>4</td>
<td>4.78</td>
<td>47.14</td>
<td>50.95</td>
<td>1.08*</td>
</tr>
<tr>
<td>15</td>
<td>4</td>
<td>4.78</td>
<td>58.50</td>
<td>54.95</td>
<td>0.94**</td>
</tr>
<tr>
<td>12</td>
<td>8</td>
<td>4.78</td>
<td>64.12</td>
<td>50.95</td>
<td>0.79**</td>
</tr>
<tr>
<td>12</td>
<td>4</td>
<td>3.35</td>
<td>47.14</td>
<td>42.14</td>
<td>0.89**</td>
</tr>
<tr>
<td>SMR – HWR</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>6</td>
<td>4.78</td>
<td>48.79</td>
<td>50.95</td>
<td>1.04*</td>
</tr>
<tr>
<td>15</td>
<td>6</td>
<td>4.78</td>
<td>59.55</td>
<td>54.95</td>
<td>0.92**</td>
</tr>
<tr>
<td>12</td>
<td>12</td>
<td>4.78</td>
<td>61.79</td>
<td>50.95</td>
<td>0.82**</td>
</tr>
<tr>
<td>12</td>
<td>6</td>
<td>3.35</td>
<td>48.79</td>
<td>42.14</td>
<td>0.86**</td>
</tr>
</tbody>
</table>

(*) reference scenario,  
(**) perturbed values

To calculate the data of Table A.22, the exact expression (equation 29, Annex B) has been used because the first order perturbation approach (formula 32, Annex B) is not valid because of the high non/linearity of \(C_N\) with respect to the discount rate, \(r\), and construction time, \(T_{Ct}\). In contrast \(C_A\) is highly linear with respect to \$/GJ, so the perturbation formula could be used without introducing much uncertainty.
As can be seen from Table A.22, the variables that most influence the RI are, in order of importance: construction time, fuel reduction of the LNG alternative, and discount rate.

With four $RI$ for each INS, including the value for the reference scenario, the lowest $RI$ needs to be taken as the $RI$ index of the INS. The results of this selection could be seen in Table A.23.

### Table A.23. Robustness (Flexibility) Index Elements

<table>
<thead>
<tr>
<th>$D_1: r$</th>
<th>$d_2: T_{Cl}$</th>
<th>$d_3: S/GJ$:</th>
<th>$C_N$</th>
<th>$C_A$</th>
<th>$RI$</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMR – PWR</td>
<td>12</td>
<td>8</td>
<td>4.78</td>
<td>64.12</td>
<td>50.95</td>
</tr>
<tr>
<td>SMR – HWR</td>
<td>12</td>
<td>12</td>
<td>4.78</td>
<td>61.79</td>
<td>50.95</td>
</tr>
</tbody>
</table>
Chapter A.4.
INPRO ACCEPTANCE LIMITS

As discussed in TECDOC-1434 (Chapter 3 of Ref. [A.15]) the assessor could develop his specific criteria consisting of indicators and the acceptance limits, always following the requirement of the INPRO methodology that the criteria be logically independent and a measure of how well a the user requirement is being met. If the assessor keeps the INPRO indicators, he could still change the acceptance limits.


Acceptance Limit AL1.1: \( \frac{C_N}{C_A} < k \) Where \( k \) is a factor less, equal or greater than one fixed by the INPRO assessor depending on other costs and credits not included in the indicator calculation.

In agreement with the case description, there is no particular support of one option to the other, so in principle for the hypothetical assessor \( k = 1 \). So the acceptance limit will be taken as \( C_N \leq C_A \), which strictly equals the INPRO proposal. The result of the comparison with the indicator could be seen in Table A.24.

A.4.2. Acceptance Limit of UR1.2.

Acceptance Limit AL1.2.1.1: \( IRR_N > IRR_{\text{LIMIT}} \) Where \( IRR_{\text{LIMIT}} \) is the minimum acceptable level required by the investor for competing technologies of comparable size.

Acceptance Limit AL1.2.1.2: \( ROI_N > ROI_{\text{LIMIT}} \) Where \( ROI_{\text{LIMIT}} \) is the minimum acceptable level required by the investor for competing technologies of comparable size.

In a very simple market frame of this hypothetical case, the financial figures of merit could be derived directly from the market rules estimated for nuclear projects. This has been discussed in the section A.2.5 Step 5 of this example. The acceptable values of the financial figures of merit have been summarized in Table A.13, with 14% of \( IRR_{\text{LIMIT}} \) and 15% of \( ROI_{\text{LIMIT}} \) per year.

The result of the comparison with the indicators could be seen in Table A.24.

Acceptance Limit AL1.2.2: \( Investment_N < Investment_{\text{LIMIT}} \) Where \( Investment_{\text{LIMIT}} \) is the maximum level of capital that could be raised in the market climate.

In a very simple market condition, the investor needs to have a capacity to raise funds that in general depends on the market share and the cash flow.

Estimating that the largest company has 50% of the market share, and the profit margin is 10% of the total income, each year the profit could range between 100 to 150 million of
USD. Investing (for the financial point of view) the profit of 4 years could produce a capital availability of 400 to 600 millions of USD.

In this hypothetical case it could be assumed (for simplicity) that the high payback time in a developing country, the total amount of money that is conceivable to be used (upper limit) is approximately 50% higher than the previous value: This gives an upper limit of 900 Millions of USD.

The result of the comparison with the indicator could be seen in Table A.24.

**A.4.3 Acceptance limit of UR1.3**

Acceptance Limit AL1.3.1: Licensing ≥ Licensing\textsubscript{LIMIT} means that the reactor licensing maturity is an acceptable value depending on the time frame till the date for deployment.

For the very short time frame of the assessor (planning an INS for the year 2010) no less than Licensing\textsubscript{LIMIT} = 0.5 could be used in this example, because it is credible that in approximately 5 years the last two stages could be fulfilled. A comparison with the indicators could be seen in Table A.24.

Acceptable Limit AL1.3.2: \( T_{C_l} \leq T_{C_l\text{LIMIT}} \) for a comparable energy source

The comparable energy source from the construction time point of view could be the CCGT (a classical base load option for this type of country). A factor of \( f = 0.5 \) could be used because more than 50% of higher construction time looks unreasonable in a strongly market oriented time frame.

Then using the construction time of the CCGT of Table A.8 gives a limit of: \( T_{C_l\text{LIMIT}} = 4.5 \) years.

A comparison with the calculated indicator could be seen in Table A.24.

Acceptance Limit AL1.3.3. Yes.

Within this example the indicator for this acceptance limit was not dealt with.

**A.4.4. Acceptance limit of UR1.4**

Acceptance Limit AL1.4.1: \( RI > 1 \) for all the critical economic indicators.

The acceptance limit is directly compared with the indicators in Table A.24.
Chapter A.5.
Conclusions

The data presented in Table A.24 (end of this chapter), indicate that for most of the economic indicators both SMRs considered are competitive with the alternative energy source, that is both INS have potential to fulfill the INPRO economic requirements. But for two of the indicators, namely the total investment, IN 1.2.2, and the robustness, IN 1.4.1, the SMRs do not meet the associated acceptance limits. Thus, the SMRs do not meet URs 1.2 and 1.4 and hence do not meet the Economic Basic Principle. Such a conclusion enables the assessor to identify the key indicators for the reference scenario, namely, IN1.2.2 (total investment) and IN1.4.1 (robustness), where development work is required to bring these indicators into compliance with the acceptance limit.

By examining the sensitivity of these key indicators to changes in the assumed properties of the SMRs, it is possible to identify the R&D strategies that might bring these indicators into compliance with the acceptance limits. For example, Figure A.5.1 shows how the robustness index and the total investment change if the power output of the SMR is changed but the overnight capital cost, per kWe installed, is kept constant.

![Figure A.5.1 Variation of the Robustness Index RI and the total investment M/US$ with changes in the electrical Power of a SMR](image)

In this example, the investment cost decreases with power output, and the investment acceptance limit of $900M would be met at a power of about 435MWe. But the robustness index also decreases somewhat with power output whereas to meet the acceptance limit it is necessary to increase this index. I.e., the effect of reducing the power output moves the RI in the wrong direction.
Figures A.5.2 and A.5.3 illustrate the potential impact of reducing the overnight cost of construction, Figure A.5.2, and of reducing the construction time and hence the interest during construction, Figure A.5.3.

![Graph showing the variation of the Robustness Index RI and the total investment M/US$ with changes in the overnight capital cost ON of a SMR](image)

Figure A5.2 Variation of the Robustness Index RI and the total investment M/US$ with changes in the overnight capital cost ON of a SMR

From Figure A. 5.2 it can be seen that a reduction in overnight costs leads to improvements in both the investment indicator and the robustness indicator but that the improvement is not adequate to bring them into compliance with the acceptance limits. From Figure A.5.3 it can be seen that reducing the construction time has a strong positive influence on the robustness indicator, as would be expected since, as discussed in Section A.3.3 of this annex, the variable that most influences the RI is construction time.

Thus, the sensitivity plots indicate that the R&D strategy to be followed should have as its goals the reduction of the unit size of the SMR while maintaining the overnight cost ($/kWe installed) close to that for the larger sized unit (to bring the investment indicator into compliance) and the reduction of construction time to bring the robustness indicator into compliance. Reducing construction time also reduces interest during construction and hence total investment.

So far in the discussion, we have considered the implications of the results of the economic assessment from the perspective of an INS developer. What might the hypothetical utility conclude from the assessment? One conclusion that might be arrived at is that an SMR would represent an attractive investment (the SMR is cost competitive and the financial figures of merit, IRR and ROI, are attractive) if the issues of robustness and total investment could be managed in some way. The utility might recognize, given that the annual consumption of electricity is expanding at ~4% per year, that the cash flow of the utility and hence its investment limit (acceptance limit for IN1.2.2) is increasing with time. Thus, while it might not be possible to adopt an SMR in the time frame of 2010 –2013, the
planning interval for the example, in a longer planning horizon, the utility could consider an SMR as a viable supply option. The fact that vendors are actively working to reduce capital cost, both in absolute costs and in $/kWe, and that at least one vendor is working to achieve a specific capital cost of $1000/kWe (see for example references [A16] and [A17]) greatly increases the likelihood that the longer term, say 2013 to 2017, the investment criterion could be met.

![Graph](image)

Figure A. 5.3 Variation of the Robustness Index and the total investment with changes in the construction time.

What about the robustness index? If the RI were the last remaining obstacle to selecting an SMR, a utility would look for opportunities to cover the risk underlying the RI. Three factors were considered in the RI, namely, in order of importance, failure to keep to the construction schedule, reductions in the price of LNG, and an increase in the discount rate from 12% to 14%. In principle, a utility could negotiate with a vendor to protect itself from the first and last of these risk factors. Since in the hypothetical example, the utility is purchasing the SMR from an off-shore vendor, the utility could seek to protect itself by negotiating penalties for delays in construction, noting that some vendors have delivered turn key, off-shore, SMR projects on or even ahead of schedule, and could seek financing from the vendor country at a rate that is compatible with, or better than, the reference discount rate of 12% assumed in the example.

Assuming the first and last of the three risks could be addressed, the utility would still be faced with the risk that the competitiveness of the SMR, as measured by the LUEC, compared with a CCGT fueled by LNG, would be adversely affected by a decrease in the price of LNG. But, conversely, the utility would also face the risk that the competitiveness of the CCGT option would be adversely affected by an increase in the cost of LNG which, on the surface, would seem to be just as likely. Faced with this dilemma the utility might consider a strategy of expanding its capacity using a judicious combination of both SMRs and CCGTs. Thus, it might adopt as a reference plan, the construction of a series of SMRs,
committing to the first in about 2013 when the criterion on investment is met, and then to subsequent units at intervals of say 5 to 7 years, but be prepared to substitute CCGTs should the price of LNG drop rather than increase slowly as used as the base case in the hypothetical example.

Energy planning is not necessarily straightforward but it is an important responsibility of governments and energy suppliers. The example presented in this annex illustrates how an economic analysis of supply options can be used to guide the development of an INS to meet a hypothetical but not un-realistic, set of market conditions and at the same time illustrates how such an assessment can be used as an aid to energy supply planning.
### Table A.24. Indicators and Comparison with Acceptance Limits

#### Judgment on potential of INS

<table>
<thead>
<tr>
<th>INS</th>
<th>Indicator Value</th>
<th>Acceptance Limit</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Indicator IN1.1.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$C_{N-SMR PWR}$</td>
<td>47.14</td>
<td>&lt; 50.95</td>
<td>mills/KWh</td>
</tr>
<tr>
<td>$C_{N-SMR HWR}$</td>
<td>48.79</td>
<td>&lt; 50.95</td>
<td>mills/KWh</td>
</tr>
<tr>
<td><strong>Indicator IN1.2.1.1.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$IRR_{SMR PWR}$</td>
<td>15.68</td>
<td>≥ 14</td>
<td>%/year</td>
</tr>
<tr>
<td>$IRR_{SMR HWR}$</td>
<td>15.54</td>
<td>≥ 14</td>
<td>%/year</td>
</tr>
<tr>
<td><strong>Indicator IN1.2.1.2.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ROI_{SMR PWR}$</td>
<td>24.43</td>
<td>≥ 15</td>
<td>%/year</td>
</tr>
<tr>
<td>$ROI_{SMR HWR}$</td>
<td>19.4</td>
<td>≥ 15</td>
<td>%/year</td>
</tr>
<tr>
<td><strong>Indicator IN1.2.2.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Investment$_{SMR PWR}$</td>
<td>1391</td>
<td>≤ 900</td>
<td>M$</td>
</tr>
<tr>
<td>Investment$_{SMR HWR}$</td>
<td>1565</td>
<td>≤ 900</td>
<td>M$</td>
</tr>
<tr>
<td><strong>Indicator IN1.3.1.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Licensing$_{SMR PWR}$</td>
<td>.5</td>
<td>≥ .5</td>
<td>None</td>
</tr>
<tr>
<td>Licensing$_{SMR HWR}$</td>
<td>1</td>
<td>≥ .5</td>
<td>None</td>
</tr>
<tr>
<td><strong>Indicator IN1.3.2.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$T_{CI SMR PWR}$</td>
<td>4</td>
<td>≤ 4.5</td>
<td>years</td>
</tr>
<tr>
<td>$T_{CI SMR HWR}$</td>
<td>7</td>
<td>≤ 4.5</td>
<td>years</td>
</tr>
<tr>
<td><strong>Indicator IN1.3.3.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Political Commitment</td>
<td>NA</td>
<td>NA</td>
<td>Logical</td>
</tr>
<tr>
<td><strong>Indicator IN1.4.1.</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$RI_{SMR PWR}$</td>
<td>0.79</td>
<td>&gt;1</td>
<td>None</td>
</tr>
<tr>
<td>$RI_{SMR PWR}$</td>
<td>0.82</td>
<td>&gt;1</td>
<td>None</td>
</tr>
</tbody>
</table>
Chapter A.6.

References


ANNEX B: Generation Cost methodology

Chapter B.1
Power Generation Cost Methods

This annex describes the methodology used for calculating generation costs in accordance with the INPRO methodology. It explains the approach and provides a minimum set of equations to calculate the generation costs, and highlights the main parameters needed for the calculation. It shows some important general definitions but does not discuss in detail all the concepts.

The objective of this chapter is to clarify the method used for classical single plant cost calculation, but starting from general enough principles to use the same definitions for more complicated INS. In INPRO, assessors using the INPRO methodology could be interested in proposing multi station power units and complex INS, which could comprise different reactors types at different times, operating in series or in parallel in a complex fuel cycle, with different reprocessing flows and mass transfers.

There are several methodologies available for calculating power generation costs (refs. [B1], [B2], [B3]). The IAEA report TRS-396 [B1] even includes a software package called BIDEVAL-3 to calculate power generation costs with a set of computer programs for use on PC. The adoption of standardized methodology for cost calculation is a prerequisite for fair comparison among different electricity generation options. So it is very important to define a well-accepted method in order to produce useful and unbiased results for INPRO.

The full system cost analysis, which is relevant from the energy producer point of view, calculates the overall economic impact of a power plant introduced into an existing grid, but has not been adopted in the INPRO assessment method because its results are essentially system specific and cannot be readily interpreted for comparison purposes in the INPRO scope.

Levelized Annual Revenue Requirements is a very detailed method, but requires significant additional considerations like the depreciation rate and several accounting details not relevant for INPRO scope.

For economic comparison of different types of power plants in a general frame, like INPRO, particularly with a small amount of additional detailed information like bond emissions, equities and other financing tools, Levelized Lifetime Cost is very useful (LLC). LLC was used in many comparative assessments (refs. [B4], [B5], [B6], [B7]) and is particularly suitable for INPRO, assessing the relative competitiveness in a comprehensive harmonized framework. The LLC is an adequate tool for all life cycle costs assessment as is required for INPRO’s assessment of economics (Chapter 4 of [B8]).
B.1.1 Time factor and the discount rate

In the evaluation of engineering projects, involving expenditures of funds, incurring of costs and receipt of revenues, like in the construction of electricity generation plants, all of them at different times, a systematic treatment of the effect of the time variable value of money is required. The value of money can be considered to change as it moves through time. In the present, for example, for an investment company money has a greater value than it would have in the future because it can be used for another investment project in the interim. This investment could produce revenues and later the funds could be available again with some profits for a second investment project.

The present value concept provides for the shifting of money from one time to another with a corresponding shift in the value. If a given amount of money \( P_1 \) is delayed for a given time drift, the value of the money \( P \) without such delay is smaller to the initial value, so \( P/P_1 \) is a constant number smaller than 1, usually called discount factor, and represents the decrease of value due to the time drift; this constant number could be written as \( 1/(1+r) \) where \( r \) is written as a rate, and is called discount rate, defined by:

\[
P = P_1 \times \left( \frac{1}{1+r} \right) \quad (1)
\]

The value of the money referred to the initial time, or actual value, is usually called present value of the money when the reference time is taken at the present time of the project. As the base time of a project could be arbitrary defined, by using negative and positive time values, the levelized value is the present value in a specific time base obtained applying the discount rate.

If the time drift is a single year, the discount rate is called annual discount rate, and is the standard unit for evaluating the decrease of worth of the money for a time delay.

It could be easily shown, by successive application of equation (1), that the present value of a given \( P_n \) amount of money after \( n \) time periods could be written as:

\[
P = P_n \times \left( \frac{1}{1+r} \right)^n \quad (2)
\]

The levelized value \( S \) of any arbitrary time distribution of money \( P_i \) to the base time \( t_0 \) could be calculated as the summation of the individual levelized values of each amount of money referred to \( t_0 \), using equation (2).

\[
S(t_0) = \sum_{i=start}^{t_{end}} \frac{P_i}{(1+r)^{t_i-t_0}} \quad (3)
\]

The discount rate that is appropriate for the power sector may differ from country to country, and in the same country could be different from utility to utility. The discount rate could be related with the returns that could be earned on typical investment for the same
players; it may be a rate required by public regulators incorporating allowance for financial risk and/or derived from national macroeconomic analysis. It may also be related to other concepts like the trade off between costs and benefits for present and future generations.

It is important to stress that as the levelized value is the value of the money for an investor, the value needs to be computed without inflation, called real values, because the price increase by inflation do not produce additional capacity to buy or to pay for services or goods.

### B.1.2 Levelized electricity generation cost

In a project with incomes and expenditures, the levelized cost methodology discount the time series of expenditures and incomes to the present value in a specific base year by applying a discount rate. Cost elements used in the calculation are expressed in real values or constant monetary terms.

To build and operate a power system a specific cash flow for building, fuelling, operating and dismantling the plant, including waste management and refurbishment needs to be considered. The levelized value of the expenditures $E(t_0)$ could be written using equation (3):

$$E(t_0) = \sum_{t=\text{START}}^{t_{\text{ESP}}} \frac{C_{It}}{(1+r)^{t-t_0}} + \sum_{t=\text{START}}^{t_{\text{ESP}}} \frac{O&M_t}{(1+r)^{t-t_0}} + \sum_{t=\text{START}}^{t_{\text{ESP}}} \frac{F_t}{(1+r)^{t-t_0}}$$  \hspace{1cm} (4)

With:  
- $C_{It}$ = Capital Investment expenditures at year $t$
- $O&M_t$ = Operation and Maintenance (O&M) expenditures at year $t$
- $F_t$ = Fuel expenditures at year $t$

Capital expenditures need to be scheduled on a yearly basis, including all construction expenses, decommissioning and refurbishment, if a relevant refurbishment is needed during the operation life of the plant.

O&M include all costs borne by producers that do not fall within investment and fuel cost. Some of them are costs that need to be paid independently of the electricity generated and are called fixed costs, others are costs that depend on the electricity generated each year, and are called variable costs. Operation and Maintenance costs usually include the plant radioactive waste management costs and taxes.

Fuel expenditures need to be scheduled on a yearly basis. For nuclear power plants, an important cost needs to be paid previously to reach the first criticality, in order to have enough reactivity excess to generate the electricity up to the first refueling. As this first core reactivity is needed up to the end of the operational life, the first core cost is usually called first core amortization, to be distinguished from the refueling cost, required to produce the energy produced each year. Fuel expenditures need to consider all the front-end costs together with the back end costs.
Special care needs to be taken to not double counting some costs, for example refurbishment, because if it is included in the capital costs, it does not need to be added in the O&M. For heavy water nuclear reactors, some countries put the first load of heavy water in the capital expenditures and annual replacement in O&M, and other countries put all the heavy water expenses in O&M.

When nuclear systems produce commercial electricity, the net power supplied to the busbar stations, fed the grid and produce income from power selling. Assuming that during all the plant lifetime a constant price $C$ of the electricity produced is paid by the consumer, the levelized value of gross incomes $GI(t_0)$ could be written using equation (3):

$$GI(t_0) = \sum_{t=\text{START}}^{t=\text{END}} \frac{P_t \times 8760 \times Lf_t}{(1 + r)^{t-t_0}} \times C \quad (5)$$

With: $P_t =$ Net electrical power of the system at year $t$

$8760 =$ Total number of hours in a year

$Lf_t =$ Load Factor at year $t$

$C =$ Constant electricity price

By definition of the constant electricity price, $C$ does not change from year to year, so it could be extracted as a common factor for the summation.

$$GI(t_0) = C \times \sum_{t=\text{START}}^{t=\text{END}} \frac{P_t \times 8760 \times Lf_t}{(1 + r)^{t-t_0}} \quad (5b)$$

If equation (5b) is equalized to equation (4), it could be seen that there is a single, unique $C$ price that would have to be paid by consumers to repay exactly the levelized expenditures with the levelized gross income, for a give discount rate $r$. The $C$ value is independent on the time base $t_0$, and it equals to:

$$C = \frac{\sum_{t=\text{START}}^{t=\text{END}} \frac{CL_t + O \& M_t + F_t}{(1 + r)^t}}{\sum_{t=\text{START}}^{t=\text{END}} \frac{P_t \times 8760 \times Lf_t}{(1 + r)^t}} \quad (6)$$
C in formula (6) is called Levelized Lifetime Costs defined as the costs per unit of electricity generated, which are the ratio of total lifetime expenses versus total expected output, expressed in terms of present value equivalent. Levelized lifetime costs are equivalent to the average price that would have to be paid by consumers to repay exactly for capital, O&M and fuel, with a proper discount rate.

The divider could be distributed in the three terms, Capital/O&M/Fuel, in order to obtain:

\[
C = \frac{\sum_{t=\text{START}}^{t=\text{END}} C_I}{(1+r)^t} + \frac{\sum_{t=\text{START}}^{t=\text{END}} O & M_I}{(1+r)^t} + \frac{\sum_{t=\text{START}}^{t=\text{END}} F_I}{(1+r)^t} \tag{6b}
\]

Which:

\[
\frac{\sum_{t=\text{START}}^{t=\text{END}} C_I}{\sum_{t=\text{START}}^{t=\text{END}} P_I \times 8760 \times Lf_i} = LUAC \quad \text{is the Levelized Unit Lifecycle Amortization Cost (6c)}
\]

\[
\frac{\sum_{t=\text{START}}^{t=\text{END}} O & M_I}{\sum_{t=\text{START}}^{t=\text{END}} P_I \times 8760 \times Lf_i} = LUOM \quad \text{is the Levelized Unit Lifecycle O&M Cost (6d)}
\]

\[
\frac{\sum_{t=\text{START}}^{t=\text{END}} F_I}{\sum_{t=\text{START}}^{t=\text{END}} P_I \times 8760 \times Lf_i} = LUFC \quad \text{is the Levelized Unit Lifecycle Fuel Cost (6e)}
\]

The summation of all the three cost gives the Levelized Unit Energy Cost \((LUEC)\) or \(LLC\) and is equal to:

\[
LUEC = LUAC + LUOM + LUFC \tag{6d}
\]

### B.1.3. Net Present Value and Internal Return Rate

Levelized lifetime cost is not the unique financial figure or merit, for an investment project; many other financial figures of merit could be defined, e.g. Internal Return Rate, Return on Investment and Payback Time.
Many of these financial figures of merit could be calculated in case a price estimation is available. By definition, levelized lifetime costs do not properly reflect the different benefits produced by different projects if not only the costs are known, but also future price estimations are known.

The difference between incomes and expenses produce the net benefit. During the construction period there is no net income, and the investment produces a negative benefit, after the start up a positive profit is produced during all the plant lifetime. This will produce a time dependant profit or net income that could be levelized using a discount rate. For a power plant project, this levelized net income \( NI(t_0, r, C_{P,t}) \) discounted at rate \( r \) at time \( t_0 \) is equal to:

\[
NI(t_0, r, C_{P,t}) = \sum_{t=\text{start}}^{\text{end}} \frac{P_t \times 8760 \times Lf_t}{(1 + r)^{t-t_0}} \times C_{P,t} - \sum_{t=\text{start}}^{\text{end}} \frac{(CI_t + O \& M_t + F_t)}{(1 + r)^{t-t_0}}
\]  

(7)

With: \( C_{P,t} = \) Electricity busbar price at time \( t \)

The levelized net income is called *Net Present Value* (NPV) at time \( t_0 \) for the investment project and by definition is equal to equation (7b).

\[
NPV(t_0 , r , C_{P,t}) = \sum_{t=\text{start}}^{\text{end}} \frac{P_t \times 8760 \times Lf_t}{(1 + r)^{t-t_0}} \times C_{P,t} - \sum_{t=\text{start}}^{\text{end}} \frac{(CI_t + O \& M_t + F_t)}{(1 + r)^{t-t_0}}
\]

(7b)

It is clear that if the electricity price is constant and equals to the levelized lifetime cost, the net present value is zero, because a that discount rate, levelized income exactly equals the levelized expenses. The net present value could be taken as the levelized profit produced by the investment, if it considers that the discount rate is the minimum rate of return or the overall cost of money to the enterprise; but it is sometimes taken at a somewhat higher value, with the argument presented that the rate of return must be above the cost of the funds or there would be no interest in the investment. In that case it needs to be taken as a necessary condition but not as a sufficient one.

Another method to evaluate an investment project is the Internal Return Rate (IRR) method, an iterative procedure that determines the unknown discount rate that is needed to balance the stream of expenditures and benefits. It is similar to the net present value except that now the rate of return is the unknown quantity. The minimum value of return rate for a project is the IRR of that project. Then IRR could be defined:
As could be seen in equation (8) equalizing the \( NPV \) to zero makes it unnecessary to refer to a time base \( t_0 \). Then equation (8) could be rewritten as:

\[
NPV(t_0, IRR, C_{P,j}) = \sum_{t=\text{START}}^{t_{\text{END}}} \frac{P_i \times 8760 \times Lf_t}{(1 + r)^{t-t_0}} \times C_{P,j} - \sum_{t=\text{START}}^{t_{\text{END}}} \frac{(CI_t + O & M_t + F_t)}{(1 + r)^{t-t_0}} = 0 \quad (8b)
\]

From equation (8b) and (6) it is easy to see that if the price is equal to the levelized lifetime cost, the IRR equals the discount rate.
Chapter B.2.
Simplified Equation for Levelized Costs

Equation (6) and (6b) look slightly complicated because they have been written in the more general approach to be used for any innovative generation system, particularly complex nuclear systems. In complex nuclear systems several reactors types and fuel cycle plants could be combined to build a complete system, and they have the capacity to recycle the spent fuel and even to breed fertile material.

A very common approximation is to consider that all the expenditures and incomes in a year are considered at the middle of the year, and to take the money values at the middle of the year too; this approach, used in refs. [4] and [6], avoids to shift all the money values 0.5 years at the proper discount rate as it is used in other references [B5][B7]. This approach also avoids considering the energy generated each year as a continuous product, with an exponential formula for levelized costs, as used in another reference [B9].

For the usual case of a single power plant nuclear system, usually \( t_{\text{START}} = 0 \), is the start of commercial operation at full power, and for previous times (during construction or not yet full power commercial operation) the time needs to be taken as negative, so \( t_{\text{END}} = t_{\text{LIFE}} - 1 \).

Considering a constant load factor during all the lifecycle (could be corrected by adding a subtraction of a lower load factor for the first or second year), the divider of all formulas (6) could be written as:

\[
\sum_{t=t_{\text{START}}}^{t_{\text{END}}} \frac{P_t \times 8760 \times Lf_t}{(1+r)^t} = P \times 8760 \times Lf \times \left( 1 - \left( \frac{1}{1+r} \right)^{t_{\text{LIFE}}} \right) \left( 1 - \frac{1}{1+r} \right) = P \times Lh_{FP} \tag{9}
\]

Where \( Lh_{FP} = 8760 \times Lf \times \left( 1 - \left( \frac{1}{1+r} \right)^{t_{\text{LIFE}}} \right) \left( 1 - \frac{1}{1+r} \right) \) (9b)

is the levelized number of hours at full power.
B.2.1. Amortization Costs

Without decommissioning costs, and back fitting costs, the capital investment flow $CI_t$ for construction usually is divided in the total Over Night costs (also called $CI_{ON}$), and the interest during construction $CI_{IDC}$, defined as:

$$CI_{ON} = \sum_{j=T_{Ci}}^{0} CI_j \quad (10a)$$

$$CI_{IDC} = CI_{ON} \times \left( \sum_{j=T_{Ci}}^{0} \omega_j \times (1 + r)^j - 1 \right) \quad (10b)$$

With $\omega_j = \frac{CI_j}{CI_{ON}}$ (10c) equals to the normalized capital investment cash flow, and $T_{Ci}$ is the construction time or construction lead-time.

If the back fitting costs are taken as single lump costs $C_{BF}$ at time $t_{BF}$, and if the decommissioning costs are taken as a single lump costs $C_D$ at time $t_D$, the equation (6c) for capital amortization could be written as:

$$LUAC = \left( \frac{CI}{P} \right)_{ON} \frac{P}{Lh_{FP}} + \left( \frac{CI}{P} \right)_{IDC} \frac{C_{BF}}{Lh_{FP}} \times \left( \frac{1}{1 - r} \right)^{t_{BF}} + \left( \frac{C_D}{P} \right) \frac{1}{Lh_{FP}} \times \left( \frac{1}{1 - r} \right)^{t_D} \quad (11)$$

usually

$t_D = t_{LIFE} \quad (11b)$

As could be seen in equation (11), with proper units all the investment costs (overnight costs, interest during construction and back fitting and decommissioning) are expressed in ($$/KWe$$), which is very usual data published for many reactors.

Sometimes some designers supply the required value for back fitting or decommissioning in leveled values, instead of power and time; this type of data could be used if the assessor is assuming that the differences produced by the different discount rates could be neglected (or if this assumption is conservative). In that case equation (11) could be rewritten:
Checking the formula (11) with (6c), the differences are approximately 5% by comparison with published data [B6], in $/KWe and leveled values.

### B.2.2. O&M Cost

For amortization simplification it has been assumed that the load factor is constant during all plant lifecycle. The variable costs are constant during all plant lifecycle, and fixed costs are constant by definition, so all the O&M costs are constant during plant lifecycle, then (6d) could be simplified:

\[
LUOM = \left(\frac{O \& M}{P}\right)_{\text{FIX}} + \left(\frac{O \& M}{KWh}\right)_{\text{VAR}}
\]

with

\[
\left(\frac{O \& M}{P}\right)_{\text{FIX}} = \text{Fixed O&M costs.}
\]

\[
\left(\frac{O \& M}{KWh}\right)_{\text{VAR}} = \text{Variable O&M costs.}
\]

With proper units, in equation (12) the fixed O&M costs could be expressed in $/KW, and the difference with (6d) could be even lower than the difference for capital amortization.

### B.2.3. Fuel Costs

The fuel costs usually are composed of three main costs [B10]:

1. The cost of the first core load, that needs to be amortized during all the plant lifecycle. Something similar sometimes happens in other energy sources: if a gas turbine needs to have as a back up fuel a tank with fuel oil for many days at full power (for gas interruption) the fuel oil needs to amortized too.

2. The costs of each fuel reload, required to replace the uranium loss by burn up; so there is an annual refueling that will depend on the burn up and fuel core reload.

3. The costs of the fuel backend, that needs to be charged to the fuel cycle costs too.
Usually the fuel cost is given in \(($/Kg)_{FE}\), so the cost of the first core load is equal to:

\[
F_{1st\,CORE} = \frac{P}{\eta \times \delta_{th}} \times \left( \frac{\$}{Kg} \right)_{FE}
\]  

(13)

with \(\eta = \) net efficiency of the plant

\(\delta_{th} = \) power density of the core in Thermal Power/Kg of fuel.

For a nuclear reactor with approximately one annual refueling, each year the costs associated to refueling are equal to, with proper time units of fuel burn up \(Q\):

\[
F_{RELOAD_{j}} = \frac{\left( \frac{\$}{Kg} \right)_{FE} \times P}{\eta} \times Q
\]

(14)

The back end cost is usually paid in \(($/Kg)_{SF}\) of spent fuel; it could be taken as a charge proportional to each reload, thus, the annual expenditures are equal to (with proper time units of burn up):

\[
F_{BACK-END_{j}} = \frac{\left( \frac{\$}{Kg} \right)_{SF} \times P}{\eta} \times Q
\]

(15)

Using these approximations, the fuel cycle costs could be calculated by adding equation (13), (14) and (15) and dividing by equation (9), the result for the fuel cycle cost is then:

\[
LUF_{C} = \frac{\left( \frac{\$}{Kg} \right)_{FE}}{\eta \times \delta_{th} \times Lh_{FP}} + \frac{\left( \frac{\$}{Kg} \right)_{FE}}{Q \times \eta} + \frac{\left( \frac{\$}{Kg} \right)_{SF}}{Q \times \eta}
\]

(16)

Later on it will be seen that the different \(($/Kg)\) in equation (16) depend on the discount rate.
B.2.4. Total levelized unit energy costs

The simplified formula of the total levelized unit energy costs could be calculated by adding equations (11), (12) and (16), that gives:

$$LUEC = \frac{CI_{ON} + CI_{IDC} + C_{BF} \left( \frac{1}{1-r} \right)^{t_{sg}} + C_{O} \left( \frac{1}{1-r} \right)^{t_{op}}}{P \times L_{h_{FP}}} + \frac{O \times M}{P} + \frac{S}{K_{g} \times \eta} + \frac{S}{K_{g} \times \eta} + \frac{S}{Q \times \eta} + \frac{S}{Q \times \eta}$$

The formula (17) has been obtained from the more general expression (6c)+(6d)+(6e) or (6f) for LUEC, so its accuracy depends on the accuracy of the assumptions. As a test of the range of validity, (17) could be tested by a comparison of published values of LUEC using (6f).

In Ref. [B6] it could be found all the data (approximately 70 data inputs) needed for (6f) and also the data for (17), only an input of 14 data. Checking the published LUEC in Ref. [B6] and the result of (17), the discrepancy is 1.7%.

If one user of the simplified formula wants to produce even more accurate results, the validity of the assumptions could be checked, and very simple corrections could be introduced if more accurate results are needed.

For example in Ref. [B6] its very clear that the load factor (75%) is taken constant only after the second commercial operation, previously the total number of hours was taken as 5000 and 6000 hours, instead of the 6626 hours resulting as 75% of 8760 hours. Then $L_{h_{FP}}$ could be changed to $L_{h_{FP}}^*$ in which the levelized additional hours included in (9b) has been subtracted using the correction:

$$L_{h_{FP}}^* = L_{h_{FP}} - \left( \frac{8760 - 5000}{1 + r} \right)$$

With this very simple elemental correction the difference between published and calculated values using the simplified (17) formula is 0.06%, which is similar to the uncertainty introduced by the number of digits used in the input data.

Thus, an assessor using the INPRO methodology is not forced to use always computer codes to calculate the economic indicators. The tools needed will depend on the accuracy that the assessor is looking for and the complexity of his INS, particularly if he considers...
that even taking into account the equation (6f) is in principle an exact calculation of levelized energy costs. INPRO’s scope is for INS in up to 50 to 100 years ahead in the future, so there is an inherent limit of LUEC accuracy and natural uncertainties involved in this type of calculation. Sometimes it is better to spend efforts in studying trends and developing the scenario, than to perform a detailed calculation without too much effort into the validity of the assumptions.

If the INPRO assessor has an INS with more than one reactor type, the same type of analytical simplification from (6f) to (17) could be used, and a very simple formula for very complex systems with several types of nuclear power plants and fuel cycle installations could be derived. Such type of work is encouraged if a proper balance wants to be taken between the accuracy of the inherent uncertainties of an INRPO scope of assessment.
Chapter B.3
Simplified formulas to calculate IDC

The formula (10b) and (10c) could be directly used to calculate the interest during construction, a very important cost contributor in nuclear energy generation costs.

But to compute (10c), the detailed cash flow per year is required, and this flow is available for many plants (refs [B4], [B6]), but usually for plants built in the past, and only few times this figure of merit is available for advanced designs of power plants. The designers need to perform a detailed engineering job in a well-developed project to produce useful, credible data. Then, for some innovative products in an earlier stage of development, as sometimes could be the case for an assessor using the INPRO methodology, there is no such information available, or maybe the designer published a value of IDC at a given discount rate [B11] but the assessor is interested into using another discount rate.

For simplified evaluations different types of IDC could be defined. In this section several methods will be explained and compared with detailed calculation in order to give the assessor simplified formulas useful for innovative plants in the early design stage.

B.3.1. Mean Investment Time

For some economic evaluation (water desalination [B12]) the IDC of the power plant is calculated assuming that all the investment is paid at the middle of the construction lead time, then equation (10b) could be directly replaced by

$$ CI_{IDC} = CI_{ON} \times \left( 1 + r \right) \frac{T_{Ct}}{2} - 1 $$ (19)

B.3.2. Constant Cash Flow

Other simplifications that could be found in some references, like the US assumption for CCGT in Ref. [B6] or the UK case for municipal waste incineration [B4] is a constant payment cash flow during all the construction time; then (10c) formula for dimensionless cash payment could be replaced for the constant factor:

$$ \omega_j = \frac{1}{T_{Ct}} $$ (20)

And then (10b) could be calculated by:

$$ CI_{IDC} = CI_{ON} \times \left( \frac{(1+r)^{T_{Ct}} - 1}{T_{Ct} \times r} \right) $$ (21)
B.3.3 Effective investment time

It is easy to see that both equations (19) and (21) could be expressed in a more general way assuming that all the investment is paid at a single moment, defined as an effective lead time $T_{\text{effective}}$, that produces the same IDC that is produced by the detailed cash flow.

This effective single payment could be found in some cases, like the German consideration of nuclear and coal plants in Ref. [B4], and this expression could be written:

$$CI_{\text{DC}} = CI_{\text{ON}} \times (1 + r)^{T_{\text{dev}} - 1} \quad (22)$$

The advantage of the more general expression (22) is that if the IDC is known at some discount rate ($r_1$), the $T_{\text{effective}}$ to produce the same IDC($r_1$) could be calculated, and then it is possible to calculate the IDC($r_2$) at another discount rate ($r_2$) assuming that the change in the $T_{\text{effective}}$ is negligible.

Knowing the IDC at a given discount rate $r_1$, using (22) could be calculated $T_{\text{effective}}$ as:

$$T_{\text{effective}} = \frac{\ln \left( \frac{CI_{\text{DC}}(r_1)}{CI_{\text{ON}}} + 1 \right)}{\ln(1 + r_1)} \quad (23)$$

B.3.4. First moment effective investment time

Some authors use the time calculated first moment, also called “center of gravity of payments” as the effective investment time. This is the case in the German assumption for nuclear and coal plants in Ref. [B4].

To calculate the IDC value, the formula is equal to (22), but $T_{\text{effective}}$ is calculated by:

$$T_{\text{effective}} = \frac{\sum_{j=0}^{0} \omega_j \times j}{\sum_{j=0}^{0} \omega_j} = \sum_{j=0}^{0} \omega_j \times j \quad (24)$$

This approach could be taken as a special case of (22), in which the effective investment time of (24) has been calculated by the first order expansion of (10b).

B.3.5. Comparison of approximate solutions for IDC

Many solutions have been shortly described in order to calculate the IDC, for a given known or unknown cash flow. For an assessor, the differences between the exact calculation of equation (10b) and the approximate solutions of equations (19), (21), (22) and (24) need to be compared for useful cases. In published reports (refs [B4], [B6]) IDC values at two discount rates (5% and 10% per year) could be found including all the detailed cash
flow, so these published results could be compared with the exact formula of equation (10b) and its approximations in equations (19) (21) (22) and (24).

This will give the assessor enough information to estimate the IDC if he doesn’t know the detailed cash flow because the INS is in an early design stage, or because he wants to use a first order approximation to perform a fast calculation.

The values of IDC for nuclear power plants will be compared at the two discount rates (5%/year and 10%/year) using the values of Ref. [B6], because the nuclear power plants are the power options with the largest construction time in the report, and this usually implies a very challenging cash flow.

To compare directly the results of equations (10b) (19) (21) (22) and (24) with Ref. [B6], two additional elements need to be considered.

In the report the present values are calculated at start time of the year zero but the costs are assumed at the middle of the year, then a half-year time discount correction needs to be added to all the formulas.

For the Canadian HWR, the cost of heavy water is calculated as a capital amortization with a specific model for its amortization, and is not included in the power plant cash flow investment, so the IDC for heavy water needs to be added to the power plant IDC. This is not the case for the Korean HWR.

Table B.1 shows the comparison of the published IDC [B6] with the calculated values with the given formulas.

Comparing the values of the exact formula (10b) with the published data, the discrepancies are similar to the number of digits used in the published report, and thus show the accuracy of the formalism used in this section.

The mean investment time formula (19) has a relative small error of only 8%, which is a good value, if it’s considered that only the total construction time is needed. That’s the reason why the reference [B12] used that method.

The worst method is the constant cash flow model, equation (21), because the error is higher than 20% for the lower discount rate. Therefore this method is not a good tool for INPRO. Studying the reference that used such a model [B6], it turns out they used it only for cases like CCGT with short construction time, and therefore lower errors for that case could be expected.
Table B1. Comparison of published IDC [B6] and calculated values with different formulas.

<table>
<thead>
<tr>
<th>Country</th>
<th>Data from [B6] in $/KWe</th>
<th>Calculated values of IDC in US$/KWe using data from [B6]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$C_{ON}$</td>
<td>IDC</td>
</tr>
<tr>
<td></td>
<td>Capital</td>
<td>Conting.</td>
</tr>
<tr>
<td>Canada</td>
<td>1697</td>
<td>85</td>
</tr>
<tr>
<td>Canada</td>
<td>1518</td>
<td>76</td>
</tr>
<tr>
<td>Finland</td>
<td>2256</td>
<td>113</td>
</tr>
<tr>
<td>France</td>
<td>1636</td>
<td>49</td>
</tr>
<tr>
<td>Japan</td>
<td>2521</td>
<td>0</td>
</tr>
<tr>
<td>Korea</td>
<td>1637</td>
<td>0</td>
</tr>
<tr>
<td>Spain</td>
<td>2169</td>
<td>0</td>
</tr>
<tr>
<td>Turkey</td>
<td>1968</td>
<td>55</td>
</tr>
<tr>
<td>Brazil</td>
<td>1550</td>
<td>155</td>
</tr>
<tr>
<td>Russia</td>
<td>1521</td>
<td>350</td>
</tr>
<tr>
<td>US</td>
<td>1441</td>
<td>144</td>
</tr>
<tr>
<td>Brazil</td>
<td>1530</td>
<td>153</td>
</tr>
<tr>
<td>% Average Difference with published IDC</td>
<td>0.14</td>
<td>0.11</td>
</tr>
</tbody>
</table>
The more accurate model is the effective investment time, equation (22); this is not a surprising result because it has been obtained as an improvement of equation (19). The only disadvantage of such a model is that it requires at least one IDC at a given discount rate, and this value is not always available for all the technical options.

The first moment model or center of gravity of payment model, equation (24), produces very good results (almost close to the effective investment time), but requires a detailed cash flow description. If the cash flow is available, it could be taken as a useful faster evaluation compared with equation (10b), but it is still better to use the exact calculation if it’s available to perform the evaluation.

Thus, it could be concluded that the usefulness of the formula depend on the data available. Table B2 shows a summary of what could be a good formula to be used depending on the data available.

**Table B2. Formula to be used to calculate IDC depending on data**

<table>
<thead>
<tr>
<th>Available Data</th>
<th>Suggested Formula</th>
<th>Number</th>
<th>Error in IDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Detailed cash flow</td>
<td>Exact calculation</td>
<td>(10b)</td>
<td>0 %</td>
</tr>
<tr>
<td>Only Construction Time</td>
<td>Mean investment time</td>
<td>(19)</td>
<td>8 %</td>
</tr>
<tr>
<td>IDC at some discount rate</td>
<td>Effective investment time</td>
<td>(22)</td>
<td>1 %</td>
</tr>
</tbody>
</table>
Chapter B.4
Perturbed Values and Robustness Index.

Every economic indicator depends on the data used in its calculation, and the accuracy of the index depends on the accuracy of the input data. Thus, uncertainties in input data will be related to the indicators uncertainties.

For INPRO, the assessor is dealing with different scenarios far away in the future, so he could use expert’s judgment, computer modeling and study of published or internal data, but always at the end he has to introduce assumptions and forecasts that will introduce uncertainties in the input data for the INPRO analysis.

There is no way to circumvent such uncertainties, but a robust INS will be the one with indicators, which are less dependant on the data used.

For example, gas turbines with very low capital costs (sometimes between the range of 25% or 30% of the cost of a nuclear reactor investment for the same power), will have capital amortization costs much lower than nuclear, and thus, the sensibility to a change in the discount rate will be much lower than nuclear. On the other side, the same gas turbine will have a total costs much sensible to fuel price changes, and thus, nuclear will be less sensible to fuel price instabilities than gas turbines.

Then it could be said that gas turbines are more robust (flexible) than nuclear plants in case of capital uncertainties, but nuclear plants are more robust than gas turbines in case of fuel prices uncertainties.

It is easy for any real-type INPRO indicator, after selecting which data could potentially deviate from the values used in the base case, to define a sensitivity vector calculated as the partial derivate of the indicator for each data. If the indicator could be calculated using an analytical expression it could be directly calculated by its derivate, but if the indicator is a more complex numerical calculation, the derivate could be calculated by the simple linear first order approximation, using the formula (25).

\[
P(i_e, d_j) = \left( \frac{\partial i_e}{\partial d_j} \right) \approx \left( \frac{\Delta i_e (d_j + \Delta d_j)}{\Delta d_j} \right) \quad (25)
\]

In which:

\[ P(i_e, d_j) = \] sensibility vector for the indicator \( i_e \) for the data \( d_j \).

This sensibility vector indicates, in each data direction \( d_j \), what is the change in the indicator \( i_e \) for a unitary change on the data, and the sign indicates if the value of indicator increases or decreases depending on a positive change on the data.
But this sensibility does not represent the final risk produced by the uncertainty, because not all the data could change the same order to magnitude. For example the load factor of a nuclear power plant could change from 85% to 75%, as was proven by operative experience, but the price of natural gas could change 100% or more in a relatively short time. Prices for fossil fuels are rather unstable, and uranium price for example has changed several times the last 20 years, but the velocity and frequency of uranium price changes are substantially different to the fossil fuels price changes.

The real risk for an investor interested in a given INS due to market changes (or robustness of the INS) depends on the sensibility of the data used and the potential size of changes in the data too. Then to compute the real INS’s robustness he needs to consider a range of all the relevant input data between a data upper limit ($d_{j,UL}$) and lower limit ($d_{j,LL}$), and the base case $d_j$ values lies between those limits:

$$d_j \in \{d_{j,LL}, d_{j,UL}\} \quad (26)$$

To define this range the assessor using the INPRO methodology needs to use some expert judgment about the different markets trends, past history and future challenges. These ranges are not necessary symmetric around the data value, so two incremental changes could be defined depending if the parameter could increase or decrease:

$$\Delta^+ d_j = d_{j,UL} - d_j \quad (27)$$

$$\Delta^- d_j = d_{j,LL} - d_j \quad (28)$$

For these boundary values, the perturbed economic indicator value could be determined, by calculating for the perturbed data the new value:

$$\Delta^+ i_{e,d_j} = i_e(d_j + \Delta^+ d_j) \quad (29)$$

Where $\Delta^+ i_{e,d_j}$ is the perturbed value for the indicator $i_e$ for the data $d_j$.

The formula (29) could be simplified in more compact vectorial nomenclature. The formula could be defined as a vector by arranging the $d_j$ elements in a vector of dimension $j$:

$$\Delta^+ i_{e,d_j} = \left(\Delta^+ i_{e,d_j}\right) \quad (30)$$

The data perturbation also could be defined in a vector of $j$ dimension:

$$\Delta^+ d_j = \left(\Delta^+ d_j\right) \quad (31)$$

Then is very easy to define a first order approximation of the perturbed economic indicator vector (30) by the internal product of the sensibility vector (25) and the data perturbation (31).
This formula is valid depending on the validity of the first order expansion; unfortunately for large discount rate changes this approximation is not valid for levelized capital amortization. In that case the exact (29) expression needs to be used.
Chapter B.5.  
Simplified Leveled Fuel Costs:

B.5.1. Nuclear Fuel Costs:

The fuel cycle costs depend on the value of each fuel given in $(\$/\text{Kg})_{FE}$, and could be calculated using formula (16). Depending on the assessor’s approach, different types of fuel costs could be calculated. Sometimes a given reactor plant is not constrained to a fixed fuel cost value because the assessor could be interested in having the opportunity to select different fuel suppliers, enrichment services provider or uranium purchaser.

Without an overall fuel supplier contract, if the utility is interested in having different contracts for different fuel cycle steps, the cash flow is very time dependant, and at the end the fuel costs need to be calculated in a leveled way. Then $(\$/\text{Kg})_{FE}$ costs is strictly dependant on the discount rate.

Then the fuel costs need to be computed using the detailed cash flow calculation, including all the fuel cycle steps. Additionally the first core in a nuclear reactor never is built with the total core with the same enrichment that is used in refueling. The first core could use a different enrichment grade, dividing the first core load in different enrichment sections. It is very usual that the reactor designers specify the first core load enrichment distribution.

For the economic point of view this is relevant because in that case the $(\$/\text{Kg})_{FE}$ fuel costs is very different to the $(\$/\text{Kg})_{FE,\text{Refuelling}}$ refueling costs. Then the $(\$/\text{Kg})_{FE,1^{st}\text{Core}}$ and $(\$/\text{Kg})_{FE,\text{Refuelling}}$ could be defined depending on the different fuel compositions.

Then equation (16) could be rewritten in a different way:

$$LUFC = \left(\frac{\$}{\text{Kg}}\right)_{FE,1^{st}\text{Core}} \times \frac{\eta \times \delta_{th} \times Lh_{FP}}{Q \times \eta} + \left(\frac{\$}{\text{Kg}}\right)_{FE,\text{Refuelling}} \times \frac{Q \times \eta}{Q \times \eta} \quad (16b)$$

This type of fuel costs calculation has been extensively analyzed in several documents refs [B9] and [B10] and text books [B13], and will be shortly described here in order to have a complete first set of formulas to be used in INPRO.

All nuclear fuel cycle has different stages depending on the fuel cycle itself. For a classical OT LWR cycle, usually the stages are uranium purchase, conversion services, enrichment services, and fuel fabrication, but this type of division depends on the fuel companies structure used in different cases.

Each fuel cycle step has different production units, but usually all of them calculate their production unit for a constant uranium mass, usually 1 Kg of uranium; this unit is also
called as heavy metal (HM) mass to include plutonium recycling cycles or thorium cycles. Then for each steps the required HM mass, to be used to produce 1Kg of HM finally included in the fuel, needs to be computed, including the losses produced at the different stages.

The leveled fuel costs could be calculated as:

$$\left(\frac{\$/Kg}{FE}\right)_{FE} = \sum_{n=1}^{\text{Nstages}} \left( \frac{\$}{s_n} \times \frac{s_n}{HM_n} \times \frac{HM_n}{HM_{FE}} \times \frac{1}{(1+r)^{t_n-t_n}_n} \right)$$  \hspace{1cm} (33)

Where:

- \( \left( \frac{s_n}{HM_n} \right) = (33a) \) Quantity of services \( s_n \) per unit of \( HM_n \) required for the fuel cycle stage \( n \)

- \( \left( \frac{HM_n}{HM_{FE}} \right) = (33b) \) Quantity of heavy metal \( HM_n \) per unit of \( HM_{FE} \) required for the stage \( n \)

- \( \left( \frac{\$}{s_n} \right) = (33c) \) Specific Costs of services \( s_n \)

To calculate the heavy metal mass flow in each fuel cycle step, the fraction of losses in each fuel cycle stage, and the process mass balance needs to be known.

For example for a LWR OT fuel cycle, the only stage with a strong change in the heavy metal mass is the enrichment stage, because for isotope balance of a given unit of enriched uranium with enrichment \( \varepsilon_p \) there are required \( F \) units of uranium feed at enrichment \( \varepsilon_F \), with \( F \) given by refs [B13] and [B14]:

$$F = \frac{\varepsilon_p - \varepsilon_T}{\varepsilon_F - \varepsilon_T}$$  \hspace{1cm} (34)

where \( \varepsilon_T \) is the tail enrichment used in the enrichment plant.

The expression (34) applies to an enrichment plant without any losses, so it could be taken as an ideal expression of the HM requirement.

In any fuel cycle stage, the \( HM_n \) required in the stages \( n \) is the ideal feed of each stage to produce 1 unit of \( HM_{FE} \) with the addition of the losses of the stage \( l_n \) and the additional accumulation of losses of the \( m \) downstream stages to reach the HM content in the final fuel:

$$\left( \frac{HM_n}{HM_{FE}} \right) = \prod_{m=n}^{\text{Nstages}} \left( \frac{HM_n}{HM_{n+1}}_{\text{IDEAL}} \times (1+l_m) \right)$$  \hspace{1cm} (35)
After this correction of losses, the services calculation is very simple particularly for mining, conversion, transport and fuel fabrication, because each service price is usually calculated and compiled by a single unit of HM produced.

The only expression with a rather complex service calculation is the enrichment service, because in the enrichment process the quantity used to measure the production and consumption is the Separative Working Unit (SWU), defined as a given quantity required to enrich starting from $\varepsilon_F$ up to an enrichment $\varepsilon_P$, with a tail of $\varepsilon_T$.

The SWU requirement is defined as [B14]:

$$SWU(\varepsilon_P, \varepsilon_F, \varepsilon_T) = V(\varepsilon_P) - V(\varepsilon_F) - F \times (V(\varepsilon_F) - V(\varepsilon_T)) \quad (36)$$

With:

$$V(x) = (2x - 1) \ln \left( \frac{x}{1-x} \right) \quad (36a)$$

And $F$ defined using the formula (34)

**B.5.2. Fossil Fuel Costs:**

The general expression (6e) of fuel costs could be used to calculate the fuel costs for any fossil fuel plant. In this expression only it is required for each year $t$ the fuel costs $F_t$. But this expression could be reduced to a simpler form to be used for a fast calculation in the more usual fossil fuel price projections.

Many economic evaluations of fossil fuels, refs [B4] and [B6], assume that there will be a price increase in real values (without inflation) to cope with the expansion capacity requirement and the more expensive resources for new production. For that case, the fuel price is to be calculated for a reference time $F_0$, usually the first commercial operation, with a given annual real price increase at a rate $i$. This could be written as:

$$F_t = F_0 \times (1+i)^t \quad (37)$$

with: $F_0 =$ Annual fuel expenditures the year 0

$$i = \text{Fossil fuel annual real price increase rate.}$$

This expression could be replaced in (6e) which gives:
With a constant load factor during all the lifecycle with a constant efficiency during the plant life, the formula (38) could be written as

\[
LUFC = \frac{F_0 \times \left( \frac{1}{1 + r} \right)^{t_{life}}}{1 - \left( \frac{1}{1 + r} \right)^{t_{life}}} \times \left( 1 - \frac{P \times 8760 \times Lf \times \left( \frac{\$}{GJ} \right)}{1 + r} \right) ^{t_{life}}
\]

This expression could be simplified more because the cost \( F_0 \) depends on the power output \( P \), the net efficiency of the plant \( \eta \), the load factor \( Lf \) and the fossil fuel price usually in \(($/GJ)\).

\[
F_i = \left( \frac{P_i}{\eta} \right) \times 8760 \times 3600 \times Lf_i \times \left( \frac{\$}{GJ} \right) \times \left( \frac{1}{1 + r} \right)^{t_{life}}
\]

Replacing \( F_0 \) in (39) using the formula (40) the simplest approximation of the fuel cost is produced:

\[
LUFC = \frac{3600 \times \left( \frac{\$}{GJ} \right)}{\eta} \times \left( \frac{1}{1 + r} \right)^{t_{life}} \times \left( \frac{1}{1 - \frac{i}{r}} \right) \times \left( 1 - \frac{1}{1 + r} \right)^{t_{life}}
\]

in the expression (41) is easy to verify that without price escalation \((i=0)\) the fuel cost is simply:

\[
LUFC = \frac{3600 \times \left( \frac{\$}{GJ} \right)}{\eta}
\]
Chapter B.6.
REFERENCES


<table>
<thead>
<tr>
<th>ABBREVIATIONS</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADS</td>
<td>accelerator driven system</td>
</tr>
<tr>
<td>AGR</td>
<td>advanced gas reactor</td>
</tr>
<tr>
<td>AL</td>
<td>acceptance limit (INPRO)</td>
</tr>
<tr>
<td>ALARP</td>
<td>as low as reasonably practical, social and economic factors taken into account</td>
</tr>
<tr>
<td>BOO</td>
<td>build, own and operate</td>
</tr>
<tr>
<td>BOT</td>
<td>build, own and transfer</td>
</tr>
<tr>
<td>BP</td>
<td>basic principle (INPRO)</td>
</tr>
<tr>
<td>BWR</td>
<td>boiling water reactor</td>
</tr>
<tr>
<td>CFE</td>
<td>cost free expert (INPRO)</td>
</tr>
<tr>
<td>CNS</td>
<td>current nuclear system</td>
</tr>
<tr>
<td>CR</td>
<td>criterion (INPRO)</td>
</tr>
<tr>
<td>CRP</td>
<td>coordinated research project</td>
</tr>
<tr>
<td>DTV</td>
<td>desired target value (INPRO)</td>
</tr>
<tr>
<td>DU</td>
<td>depleted uranium</td>
</tr>
<tr>
<td>EUR</td>
<td>European utility requirements</td>
</tr>
<tr>
<td>FCF</td>
<td>fuel cycle facility</td>
</tr>
<tr>
<td>FOAK</td>
<td>first-of-a-kind</td>
</tr>
<tr>
<td>FP</td>
<td>fission products</td>
</tr>
<tr>
<td>FR</td>
<td>fast reactor</td>
</tr>
<tr>
<td>GC</td>
<td>IAEA General Conference</td>
</tr>
<tr>
<td>GHG</td>
<td>green house gas</td>
</tr>
<tr>
<td>GIF</td>
<td>Generation IV International Forum</td>
</tr>
<tr>
<td>HEU</td>
<td>highly enriched uranium</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Full Form</td>
</tr>
<tr>
<td>--------------</td>
<td>-----------</td>
</tr>
<tr>
<td>HF</td>
<td>human factor</td>
</tr>
<tr>
<td>HLW</td>
<td>high level waste</td>
</tr>
<tr>
<td>HTGR</td>
<td>high temperature gas reactor</td>
</tr>
<tr>
<td>HWR</td>
<td>heavy water reactor</td>
</tr>
<tr>
<td>I&amp;C</td>
<td>instrumentation and control</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency (OECD)</td>
</tr>
<tr>
<td>ICG</td>
<td>international coordinating group in INPRO</td>
</tr>
<tr>
<td>ICS</td>
<td>individual case study (INPRO)</td>
</tr>
<tr>
<td>ICRP</td>
<td>International Commission on Radiological Protection</td>
</tr>
<tr>
<td>IDC</td>
<td>interest during construction</td>
</tr>
<tr>
<td>IGCC</td>
<td>integrated gasification combined cycle (coal power plant)</td>
</tr>
<tr>
<td>IIASA</td>
<td>International Institute for Applied System Analysis</td>
</tr>
<tr>
<td>IN</td>
<td>indicator (INPRO)</td>
</tr>
<tr>
<td>INPRO</td>
<td>International Project on Innovative Nuclear Reactors and Fuel Cycles (IAEA)</td>
</tr>
<tr>
<td>INS</td>
<td>innovative nuclear energy system (INPRO)</td>
</tr>
<tr>
<td>INSAG</td>
<td>International Nuclear Safety Advisory Group (IAEA)</td>
</tr>
<tr>
<td>IPCC</td>
<td>Intergovernmental Panel on Climate Change</td>
</tr>
<tr>
<td>IRR</td>
<td>internal rate of return</td>
</tr>
<tr>
<td>ISED</td>
<td>indicator for sustainable energy development (IAEA)</td>
</tr>
<tr>
<td>KI</td>
<td>key indicator (INPRO)</td>
</tr>
<tr>
<td>LCA</td>
<td>life cycle assessment</td>
</tr>
<tr>
<td>LCI</td>
<td>life cycle inventory</td>
</tr>
<tr>
<td>LDC</td>
<td>levelized discounted cost</td>
</tr>
<tr>
<td>LEU</td>
<td>low enriched uranium</td>
</tr>
<tr>
<td>LLC</td>
<td>levelized life time cost</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------</td>
<td>------------</td>
</tr>
<tr>
<td>LOCA</td>
<td>loss of coolant accident</td>
</tr>
<tr>
<td>LUEC</td>
<td>levelized unit energy cost</td>
</tr>
<tr>
<td>LWR</td>
<td>light water reactor</td>
</tr>
<tr>
<td>MFA</td>
<td>material flow assessment</td>
</tr>
<tr>
<td>MNFC</td>
<td>multilateral fuel cycle (INPRO)</td>
</tr>
<tr>
<td>MS</td>
<td>Member State (IAEA)</td>
</tr>
<tr>
<td>NCS</td>
<td>national case study (INPRO)</td>
</tr>
<tr>
<td>NEA</td>
<td>Nuclear Energy Agency (OECD)</td>
</tr>
<tr>
<td>NGO</td>
<td>non-governmental organization</td>
</tr>
<tr>
<td>NII</td>
<td>investment needed for national infrastructure (INPRO)</td>
</tr>
<tr>
<td>NM</td>
<td>nuclear material</td>
</tr>
<tr>
<td>NPP</td>
<td>nuclear power plant</td>
</tr>
<tr>
<td>NPV</td>
<td>net present value</td>
</tr>
<tr>
<td>NPT</td>
<td>Non-Proliferation Treaty</td>
</tr>
<tr>
<td>NOAK</td>
<td>N&lt;sup&gt;th&lt;/sup&gt; of a kind</td>
</tr>
<tr>
<td>NRC</td>
<td>Nuclear Regulatory Commission (USA)</td>
</tr>
<tr>
<td>OECD</td>
<td>Organization for Economic Co-operation and Development</td>
</tr>
<tr>
<td>OECD-90</td>
<td>SRES region of all countries belonging to OECD as of 1990</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>operation and maintenance</td>
</tr>
<tr>
<td>OT</td>
<td>once through fuel cycle</td>
</tr>
<tr>
<td>P&amp;T</td>
<td>partitioning and transmutation</td>
</tr>
<tr>
<td>PHWR</td>
<td>pressurized heavy water reactor</td>
</tr>
<tr>
<td>PIRT</td>
<td>phenomena identification and ranking table</td>
</tr>
<tr>
<td>PR</td>
<td>proliferation resistance (INPRO)</td>
</tr>
<tr>
<td>PRIS</td>
<td>Power Reactor Information System (IAEA)</td>
</tr>
<tr>
<td>Acronym</td>
<td>Description</td>
</tr>
<tr>
<td>---------</td>
<td>-------------</td>
</tr>
<tr>
<td>PSA</td>
<td>probabilistic safety analysis</td>
</tr>
<tr>
<td>PUES</td>
<td>reference price for unit of electricity sold</td>
</tr>
<tr>
<td>PWR</td>
<td>pressurized water reactor</td>
</tr>
<tr>
<td>RBI</td>
<td>relative benefit index (INPRO)</td>
</tr>
<tr>
<td>RBMK</td>
<td>graphite moderated fuel channel reactor</td>
</tr>
<tr>
<td>RD&amp;D</td>
<td>research, development and demonstration</td>
</tr>
<tr>
<td>REF</td>
<td>SRES region of countries with economic reform (formerly Eastern Europe and the Soviet Union)</td>
</tr>
<tr>
<td>RES</td>
<td>resolution (of the IAEA General Conference)</td>
</tr>
<tr>
<td>RI</td>
<td>robustness index (INPRO)</td>
</tr>
<tr>
<td>RG</td>
<td>reactor grade</td>
</tr>
<tr>
<td>ROI</td>
<td>return on investment</td>
</tr>
<tr>
<td>ROW</td>
<td>SRES region of rest of the world (beside OECD-90, Asia and REF)</td>
</tr>
<tr>
<td>RRI</td>
<td>relative risk index (INPRO)</td>
</tr>
<tr>
<td>SRES</td>
<td>Special report on emission scenarios (IIASA)</td>
</tr>
<tr>
<td>TBD</td>
<td>to be determined</td>
</tr>
<tr>
<td>TOR</td>
<td>terms of reference</td>
</tr>
<tr>
<td>UNDP</td>
<td>United Nations Development Programme</td>
</tr>
<tr>
<td>UNDESA</td>
<td>United Nations Department of Economics and Social Affairs</td>
</tr>
<tr>
<td>UNFCCC</td>
<td>United Nation Framework Convention on Climate Change</td>
</tr>
<tr>
<td>UR</td>
<td>user requirement (INPRO)</td>
</tr>
<tr>
<td>VNI</td>
<td>value of nuclear installation (INPRO)</td>
</tr>
<tr>
<td>WANO</td>
<td>World Association of Nuclear Operators</td>
</tr>
<tr>
<td>WEC</td>
<td>World Energy Council</td>
</tr>
<tr>
<td>WG</td>
<td>weapon grade</td>
</tr>
<tr>
<td>WNA</td>
<td>World Nuclear Association</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>--------------------------------------------------</td>
</tr>
<tr>
<td>WIPP</td>
<td>Waste Isolation Pilot Plant (US)</td>
</tr>
<tr>
<td>WSSD</td>
<td>World Summit on Sustainable Development</td>
</tr>
<tr>
<td>WWER</td>
<td>water cooled water moderated power reactor</td>
</tr>
</tbody>
</table>