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COST ESTIMATING GUIDELINES FOR GENERATION IV NUCLEAR ENERGY SYSTEMS

GEN IV International Forum℠

ECONOMIC MODELING WORKING GROUP (EMWG)

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FOREWORD

In March of 2003, the U.S. DOE Nuclear Energy Research Advisory Committee and the Generation IV International Forum (GIF) published *A Technology Roadmap for Generation IV Nuclear Energy Systems***.** This Roadmap described the research and development needed to have new safe, economical and reliable nuclear energy systems available for deployment before the year 2030. Among the many research and development tasks identified was the need for models and methods for economic analysis of those advanced nuclear energy systems under consideration. The needed research and development was called out in the Roadmap and further defined in supporting documents produced by the Evaluation Methodology Group and the Economic Crosscut Group.

An Economic Modeling Working Group (EMWG) was established by the GIF in 2003 to create economic models and guidelines to facilitate future evaluations of the Generation IV nuclear energy systems and assess progress toward the GIF economic goals. Members of the EMWG are appointed and supported by the individual GIF countries and work under the general guidance of the GIF Experts Group.

This report is a key element of the EMWG work to create an Integrated Nuclear Energy Economic Model for application to Generation IV Nuclear Energy Systems. It is intended to be a living document that has been be updated numerous times over the past several years to: further refine the different cost models; broaden the coverage of the economic assessment tools to energy products other than electricity, including hydrogen; and include an analysis of the economic impacts of plant size and modularity. Accompanying software, G4Econs, used in conjunction with these Guidelines facilitates consistent, comprehensible cost estimates for evaluation of the Generation IV Nuclear Energy Systems with respect to the established economic goals.

The Executive Summary and Introduction should serve as information for the GIF Policy and Experts Groups to initiate costs estimates at the appropriate times. The body of the Guidelines, along with the G4Econs software, provides the information and guidance necessary for the system development teams to perform the requested cost estimates and to assess their progress toward the Generation IV economic goals.

TABLE OF CONTENTS

List of Tables

List of Figures

COST ESTIMATING GUIDELINES FOR GENERATION IV NUCLEAR ENERGY SYSTEMS

ABSTRACT

The economic goals of Generation IV nuclear energy systems, as adopted by the Generation IV International Forum (GIF), are:

- to have a life-cycle cost advantage over other energy sources, i.e., to have a lower levelized unit cost of energy on average over their lifetime; and
- to have a level of financial risk comparable to other energy projects, i.e., to involve similar total capital investment and capital at risk.

The Economics Crosscut Group of the Generation IV Roadmap Project recommended that a standardized cost estimating protocol should be developed to provide decision makers with a credible basis to assess, compare, and eventually select future nuclear energy systems taking into account a robust evaluation of their economic viability. The GIF accepted this recommendation and established the Economic Modeling Working Group (EMWG) to develop this protocol.

This document provides a uniform set of assumptions, a uniform Code Of Accounts (COA), cost-estimating ground rules, and estimating requirements to be used in developing cost estimates for advanced nuclear energy systems. It discusses the development of all relevant life cycle costs for Generation IV systems, including the planning, research, development, demonstration (including prototype), deployment, and commercial stages.

Software models, G4Econs, accompany this document. The combination of the software and Guidelines will facilitate the development of consistent, comprehensible cost estimates to be performed by the system development teams as requested by the GIF Policy and Experts Groups.

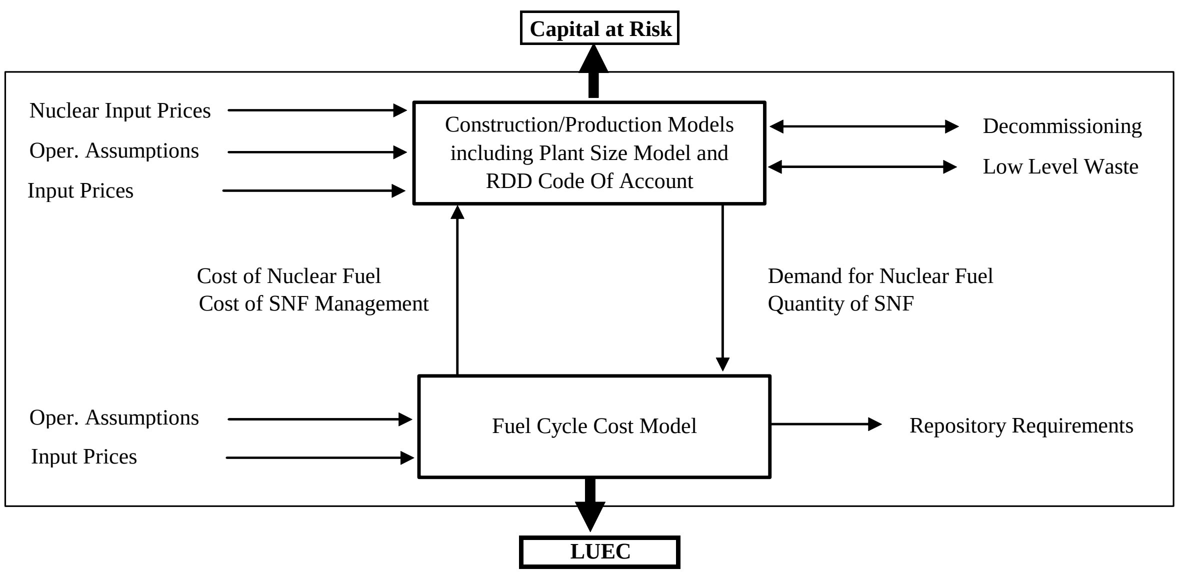
The Levelized Unit of Energy Cost (LUEC) that is evaluated includes design, construction, commissioning, operations and maintenance, fuel cycle, and decommissioning costs for the First-Of-A-Kind (FOAK) through Nth-Of-A-Kind (NOAK) commercial units. It is expected that system development teams (System Steering Committees) will provide feedback to the EMWG on these cost estimating guidelines and consult as needed with the EMWG when preparing cost and schedule estimates.

EXECUTIVE SUMMARY

This document describes the structure of an integrated economic model for Generation IV nuclear energy systems. It is accompanied by the G4Econs software (GIF/EMWG, 2006) implementing the guidelines and models. This model will be a tool for integrating cost information prepared by Generation IV system development teams during the development and demonstration of their concept, thus assuring a standard format and comparability among concepts. This methodology will allow the Generation IV International Forum (GIF) Experts Group to give an overview to policy makers and system development teams on the status of current economic estimates for each system and the relative status of the different systems with respect to the Generation IV economic goals. The Executive Summary and Chapter 1 – Introduction – should be useful to the Experts and Policy Groups in understanding and commissioning system cost estimates. The remainder of the document provides detailed information and processes to guide the system development teams in performing consistent cost estimates. Interaction with the EMWG could also help designers compare design options within a given concept, find the optimal design options, and guide their research, development, and demonstration (RD&D) program to address problems in the most economically effective way taking into account life cycle costs and capital at risk.

The overall structure of the model being developed by the EMWG is schematically represented in Figure ES.1.

Figure ES.1 Structure of the proposed integrated nuclear energy economic model (INEEM)



The development, construction, production, and fuel costs are described in some detail in the present document. The design, including programming, of the construction, production and fuel models and their integration were the early focus of EMWG working program. The energy product model is discussed in Chapter 10. Modular production considerations are discussed in Chapter 11.

Standard Code Of Accounts (COA)

The life cycle of any nuclear system, including those considered by GIF, includes expenditures over many years for such major categories as RD&D, commercial design, construction, commissioning, operations, fueling, and decommissioning. The ability to further subdivide these cost categories into activities at lower levels gives further insight into the technical and business issues associated with each concept. If subdivisions can be made in a common manner for all concepts, relevant comparisons can be achieved. This may be accomplished by using a uniform COA system. For many years the standard COA for construction and design costs was the Engineering Economic Data Base (EEDB) (ORNL, 1988a and 1988b) which was derived from an older NUS COA.

The International Atomic Energy Agency (IAEA) has developed its own account system (IAEA, 2000) that subsumes the EEDB for capital costs and develops additional codes for operation and maintenance, fuel cycle services, and other parts of a reactor system life cycle. The IAEA account system was modified slightly to create a GIF Code Of Accounts, described in Section 1.5. It is sometimes referred to as the "two-digit" level, i.e., costs are rolled-up at the level of major subsystems. It can be used to organize a cost estimate prepared using either a bottom-up or top-down approach. For RD&D costs (Chapter 3) the EMWG created a separate Code Of Accounts.

Cost Estimation Methodology

There are two approaches to cost estimation that can be considered for Generation IV nuclear energy systems:

- a top-down method based on scaling and detailed information from similar reactor systems, described in Chapter 5; and
- conventional bottom-up (cost engineering) estimating techniques, described in Chapter 6, that can be used for conventional projects close to deployment, or sections of project scope that are adequately detailed to include accounting for all construction commodities, plant equipment, and labor hours.

General ground rules and assumptions applicable to both approaches are given in Chapter 4.

New, highly innovative nuclear energy systems, such as the Lead-Cooled Fast Reactor (LFR) or the Molten Salt Reactor (MSR), are likely to have their early estimates prepared with cost-scaling equations, using formulas to account for indirect and support costs. Cost modules, using cost/size scaling equations, can be developed by system development teams. Examples of such cost modules are given in the descriptions of codes developed in Argentina (Grinblat *et al.*, 2002), France (Nisan *et al.*, 2003), and the United States (Williams, 1984).

More conventional systems, such as the Sodium-Cooled Fast Reactor (SCR), are likely to have their estimates prepared at a high level of detail. The standard cost-estimating categories and a common COA (at least at the two-digit level) are to be utilized for both methods.

Construction/Production Model

Cost estimates prepared by system design teams will report the overall direct and indirect costs for reactor system design and construction (base construction cost) and an estimate of the reactor annual operation and maintenance costs. The intent is that these costs be developed using the GIF account system described in Section 1.5, prepared by the methods outlined in both Chapters 5 and/or 6. The decision maker, however, needs more than just the overall costs in each life cycle category. Of particular interest are the cost per kilowatt of installed capacity and the cost of electricity generation (cost per kilowatt-hour) from such systems, including the contribution of capital and non-fuel operations to this figure of merit.

Chapter 7 describes how Interest During Construction (IDC), contingencies, and other supplemental items are added to the base construction cost to obtain the total project capital cost. This total cost is amortized over the economic life of the plant so that the capital contribution to the levelized unit of energy cost (LUEC) can be calculated. Operation and maintenance (O&M) and Dismantling and Decommissioning (D&D) costs, along with electricity production information, yield the contributions of non-fuel costs to the overall cost of electricity. Chapter 9 includes these algorithms, derived from earlier ORNL nuclear energy plant (NECDB) databases and reports (Delene and Hudson, 1993; and ORNL, 1988c).

Fuel Cycle Cost Model

Fuel cycle materials and services are purchased separately by the utility or the fuel subcontractor. For fuel cycles commercially deployed, there are mature industries worldwide that can provide these materials and services. Markets are competitive and prices are driven by supply and demand. The fuel cycle model requires as inputs the amount of fuel needed for the initial core and subsequent equilibrium cores, along with the fissile enrichment of the U or Pu, and for U, the transaction tails assay assumed by the enrichment service provider. The EMWG will use algorithms similar to those described in (NEA, 1994) to model the overall cost for each step and ultimately the unit cost contribution of fuel to the cost of electricity. Background material on the economic aspects of fuel cycle choices including information on nuclear materials and fuel cycle service unit costs for conventional reactor types which use commercially available fuels can be found in (NEA, 1994 and 2002). These documents include cost data on fuel reprocessing and high-level waste disposal for closed fuel cycles and spent fuel disposal for the once through option.

The present document (Chapter 8) addresses also innovative fuel cycles or fuel cycle steps for which no industrial scale or commercial facilities currently exist, especially for fuel fabrication, reprocessing, and waste disposal. For example, the Very-High-Temperature Reactor system will require high-temperature particle fuel and the Sodium Fast Reactor system might require innovative pyrometallurgical and pyrochemical facilities for fuel fabrication, reprocessing, and re-fabrication. For such systems fuel cycle service price data generally are not readily available. Therefore, it will be necessary to calculate a unit cost of fuel cycle service, such as $/kgHM for fuel fabrication, using a methodology similar to that used for LUEC calculation for the reactor system. This means that the design team must supply data on the design and construction costs for the facilities, along with an estimate of their annual production rates and operation costs. Algorithms similar to those in Chapter 7 and 9 can produce rough approximations of the unit costs.

Reactor Modularity and Non-Electricity Products

The heat generated by some Generation IV systems has the potential for uses other than electricity production, such as the production of hydrogen by thermal cracking of steam. There are also possible co-production models where the heat is used for both electricity production and process heat applications. The energy products model deals with these issues and is discussed in Chapter 10.

The cost issues and possible economic benefits that might result from modularization or factory production of all or part of a reactor system are dealt with in Chapter 11.

Note to the Reader

The reader should keep in mind that the EMWG guidelines are conceived as a living document. The G4Econs software accompanying these Guidelines uses the algorithms discussed in the remainder of this document. Sample calculations have also been published by the EMWG to demonstrate and validate the software and should be useful to those implementing these Guidelines. As the Generation IV design teams proceed in developing their systems it will be necessary for the EMWG to work with them to insure that these *Cost Estimating Guidelines* meet their needs, as well as those of the program decision makers.

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1. INTRODUCTION

1.1 Purpose of Cost Estimating Guidelines

The economic goals of Generation IV nuclear energy systems, as adopted by Generation IV International Forum (GIF), are (1) to have a life-cycle cost advantage over other energy sources and (2) to have a level of financial risk comparable to other energy projects. In addition, it is expected that Generation IV systems will be deployed in international energy markets that may be highly competitive.

An Integrated Nuclear Energy Economic Model is central to standardized and credible economic evaluation of Generation IV nuclear energy systems. The innovative nuclear systems considered within Generation IV require new tools for their economic assessment, since their characteristics differ significantly from those of current Generation II and III nuclear energy plants. The Generation IV Economic Modeling Working Group (EMWG) has undertaken a multi-year task of developing such a comprehensive model to support Generation IV International Forum (GIF) objectives. If such a model is to make realistic comparisons between the different reactor technologies/systems and provide a “level playing field” for economic evaluation, ideally the base assumptions and data underlying the model must be applied consistently to all systems. This desired goal is made difficult because, in reality, the Generation IV systems have different design bases, product streams, development costs, and deployment paths.

These Guidelines, in conjunction with the accompanying software, G4Econs (GIF/EMWG, 2006), are intended to implement the Integrated Nuclear Energy Economic Model. The Introduction and Executive Summary of the Guidelines should be useful to the GIF Policy and Expert Groups in commissioning and evaluating cost estimates for the Generation IV Systems. The body of the Guidelines provides the information necessary for the system design teams to perform cost estimates using the software.

It is anticipated that the system development teams for the various concepts will work toward developing the technical, schedule, and cost information for the six Generation IV systems:

- Gas-Cooled Fast Reactor System (GFR).
- Lead-Cooled Fast Reactor System (LFR).
- Molten Salt Reactor System (MSR).
- Sodium-Cooled Fast Reactor System (SFR).
- Supercritical-Water-Cooled Reactor System (SCWR).
- Very-High-Temperature Reactor System (VHTR).

It is anticipated that each team will begin the development of a “baseline” reactor system concept at a “pre-conceptual” level. Given sufficient funding, it is hoped that most teams may have sufficient information, with some data possibly generated by architect/engineer (A/E) subcontractors, to aid in the design and cost estimating process. It is understood that some teams may not have reached this goal due to lack of funding support from their international sponsors. Since the six reactor systems are at different stages of Research, Development and Demonstration (RD&D), knowledge required for preparation of comparable cost estimates varies widely between systems and between nations.

This fact makes early imposition of a “level playing field” cost-estimating methodology difficult, but not insurmountable. There are, indeed, cost estimating organizational concepts, inputs, and assumptions that can be applied to all six concepts that can expedite an unbiased evaluation. Among the cost estimating inputs, the following assumptions and methodologies are fixed for all concepts:

- Site characteristics for international “generic” sites.
- Design, construction, and operation labor rates, and productivity within a country (for bottom-up cost estimating).
- Construction commodity prices within a country (for bottom-up cost estimating).
- Methodology for determining economic figures of merit, such as $/kW installed and $/MWh of power generated (for both bottom-up and top-down cost estimating).
- Cost estimating categories including those that can be subdivided by a standard Code of Accounts (COA) structure, such as the GIF COA presented in these Guidelines (either for bottom-up or “top-down” cost estimating).
- Standardized cost/price assumptions for fuel cycle materials and services, such as yellow cake and enrichment services, where fuel cycle steps and costs, such as for fuel fabrication, may vary by reactor type.
- Financial parameters such as discount rates and amortization periods.
- A robust method for contingency determination (compensates for different levels of design maturity or cost basis variance).
- Stated definitions for all cost estimating terms and estimating categories.
- Stated definitions for all scheduling terms and schedule categories.
- The use of cost scaling relationships when insufficient detail is available. (The use of cost-scaling relationships and data derived from other technologies or projects is often referred to as top-down cost estimating.)

This document provides this information to all the Generation IV system design teams along with a set of standard (typical) cost figures of merit and the method to calculate them. The present guidelines will be updated as necessary. These Guidelines are accompanied by the G4Econs software that implements the models and major assumptions.

Creating guidelines early in the Generation IV International Forum program has several advantages:

- It establishes a cost-estimating language that can be used throughout the rest of the program.
- It sets a common basis for the quality and format (code-of-accounts) of cost estimates.
- It may lead to consideration of using cost scaling and cost-figure-of-merit optimization in the design process, which will enhance competitiveness. (See Appendix B for a discussion of the use of a process that integrates cost estimation with design development.)

For these reasons this document addresses the cost estimation process as well as cost estimating guidelines. The purpose of the present guidelines is to extend previous costing methods and approaches to address Generation IV systems. However, these EMWG guidelines can be applied to earlier designs and non-Generation IV concepts as well.

1.2 Differences from Previous Guidelines

For over two decades the USDOE and its contractors have been using cost estimating guidelines to ensure consistent treatment of competing reactor and non-reactor electric power production technologies.

A working set of guidelines (Delene and Hudson, 1993) were issued by ORNL in 1993 to support the non-commercial (DOE-NE) evaluation of two Liquid Metal Reactor (LMR) concepts and a Modular High Temperature Gas-cooled Reactor (MHTGR) concept, assumed to be constructed and operated under a regulated utility financial environment. These were the two “advanced” reactor technologies that DOE’s Office of Nuclear Energy was funding at that time. (One or both may serve as a “reference” set of costs for design variations.) The 1993 guidelines were supported by two other documents:

- the September 1988 Nuclear Energy Cost Data Base (NECDB) (ORNL, 1988a) which contains a detailed description of the model needed to calculate the Levelized Unit of Energy Cost (LUEC) from fossil and nuclear energy plants; and
- the highly detailed 1987 Energy Economic Data Base (EEDB) (ORNL, 1988b and 1988c) developed by United Engineers and Constructors (now part of The Washington Group, Inc.).

As the scope of the Generation IV Program evolved, it became apparent that development of new guidelines for Generation IV concepts would not be simply a matter of updating the input parameters such as labor rates, commodity prices, etc. As Table 1.1 shows, the evaluation scope is much broader for GIF concepts than for the 1993 evaluations. This is true for the technical scope, the product streams, and the international institutional environment.

Table 1.1 Comparison of cost estimating guidelines for ORNL (1993) and Generation IV

Attribute	1993 Cost Estimating Guidelines	Generation IV Cost Estimating Guidelines
Number of Technologies	2 LMR, 1 MHTGR, Pulverized Coal for comparison	6 systems (GFR, LFR, MSR, SFR, SCWR, VHTR)
Technology Class	Gen III+ but never deployed	Generation IV
Deployment Location	Hypothetical central U.S. site	International new or pre-approved sites
Financial Environment	Regulated U.S. Utility	Varies from market to market
Regulatory Environment	USNRC Licensed	USNRC in U.S. or national safety regulators; pre-approved design in country of origin
Fuels and Fuel Cycles	Once through for HEU HTGR; closed for U/Pu LMR	2 once-through systems, 4 closed cycle systems with partial or full recycle
Main products	Electricity	Missions: electricity, hydrogen, desalination, and actinide management
Reactor and Balance of Plant (BOP) fabrication concepts	On-site reactor system construction, but several modules per reactor site (GA MHTGR and GE ALMR). Rockwell LMR concept was monolithic.	Just-in-time site work, multi-modular BOP systems; both monolithic and modular concepts for reactor; modular systems use factory construction of sub-systems and on-site installation sequencing
Level of design definition	Very high, representing years of work by reactor vendors and A/Es	From very pre-conceptual to detailed engineering design (i.e., very low [MSR] to high [SCWR, SFR])
Level of cost definition	Vendor and A/Es did previous estimates. Data available at EEDB 3-4 digit level (bottom-up estimates)	Presently none to pre-conceptual analysis; reference EEDB data available for similar reactors: MHTGR, LMR, LWR. Top-down estimating required for some concepts.
Fuel cycle (FC) material and service costs	Most materials and services available commercially. Both reactor types required fuel fab/refab facility. Waste disposal costs included.	For most systems, FC costs need development for new fuel cycle steps and processes; waste costs to be included; required regional or on-site FC facilities need pre-conceptual design and cost information.
1st Commercial Plant deployment date	2000	Target 2015-2030

Therefore, wherever possible the present modeling system and the associated guidelines for economic data input, must be sufficiently generic, inclusive, and robust as to bound all possible cases that may require examination. In some areas simplifications can be made, such as the elimination of taxes and tax credits as a factor in economic analysis, thus making the model more easily applicable in different countries. In other areas, however, such as labor productivity and wage rates, new non-U.S. data are needed, which may be difficult to obtain.

In the present guidelines, 5% and 10% real (i.e., excluding inflation) discount rates are used because they are considered representative of the average cost of capital for most nuclear energy plant owners. The 5% real discount rate is appropriate for plants operating under the more traditional “regulated utility” model where revenues are guaranteed by captive markets. The 10% real discount rate would be more appropriate for a riskier “deregulated” or “merchant plant” environment where the plant must compete with other generation sources for revenues.

Generation IV cost estimation focuses on the life cycle costs for the nuclear energy plant (with single or multiple reactors). For some concepts, however, additional facilities beyond the reactor building will be needed to support the fuel cycle. These might, for example, include a regional fuel fabrication facility capable of making high temperature particle fuel for a fleet of VHTRs or an on-site pyrometallurgical facility capable of reprocessing and re-fabricating SFR metal fuel in a closed fuel cycle.

The possibility of costing non-electricity products, such as hydrogen, will require cost estimates be prepared for these on-site facilities that make use of thermal energy from the reactor(s).

For modular concepts, the cost and amortization of a factory producing major reactor systems may be required, unless an existing factory that makes equipment modules is already in use. These life cycle costs will need to be compared to the costs of typical on-site construction of most systems.

Finally, EMWG will not model unit costs for competing technologies, such as fossil or renewable generation facilities, or conventional fossil-fuel based H_2 production facilities. For electrical generation there are recent reports that deal with fossil and renewable sources using similar models to the 1993 *Guidelines*, e.g., see the ORNL Fusion study (Delene *et al.*, 2000) and the OECD study (IEA and NEA, 1998).

1.3 Relationship between the Present Guidelines and the Overall EMWG Modeling Effort

This project will upgrade existing modules of nuclear-economic models (component models such as capital, operation, fuel cycle, etc.) and develop new ones where needed. Over the duration of the EMWG support to GIF, models will be updated or developed that address each of the following four economic areas: Construction/Production Cost (or “Cost Model”); Nuclear Fuel Cycle (or “Fuel Model”); Energy Products, and modularization or factory production.

A more detailed description of what is desired for each of these four over-arching models is given in the Crosscutting Economics R&D Scope Report (USDOE and GIF, 2003). Those four models will then be integrated to provide an Integrated Nuclear Energy Economic Model, combining all the nuclear-economic models described above. This model will provide a robust tool for economic evaluation within the Viability and Performance phases of the Generation IV project.

Cost estimates for the development, design, construction, and operation costs of future energy plants will exhibit considerable uncertainty, where the magnitude of uncertainty depends on the level of reference design costing and degree of detailed engineering definition. To manage the cost estimating task for advanced nuclear energy plant concepts, a number of simplifying assumptions must be made, including:

- Systems at the deployment stage are presumed pre-licensed in their country of origin. For example, the nuclear plant licensing reform recently enacted for the U.S. allows one-step licensing and certification of a standard plant design. Underlying all this is the intent that the systems satisfy the overall safety criteria for Generation IV.

- The NOAK plant is assumed to be built such that its cost and schedule variations compared to the FOAK are known. (See Appendix E)
- A pre-approved – licensed – site exists for plant construction.
- The assumed finance and business model is such that project financing is available for all phases of the final engineering design, site development, plant layout, owner's costs, construction, and commissioning of a plant.
- No provision is made for *force majeure*, war, labor strikes, or future changes in regulatory requirements.

The present guidelines are intended to provide a consistent comparison between the advanced reactor technologies under consideration. The costs obtained using the guidelines are intended to be reasonable estimates that envelop the ultimate cost in an uncertain environment. The reported estimates should represent the most likely costs, including the appropriate contingency (see Appendix A).

Several example calculations using these Guidelines and the G4 Econs software, in varying stages of development, have been performed by the EMWG. These sample calculations are available of the GIF website. (See References at the end of this section.)

1.4 Definitions of Cost Estimating Terms

The following definitions of terms will provide the background necessary for interpreting the present guidelines. It is understood that some of these terms will not be used or applicable until much later in the system development and deployment cycle.

BOP (Balance of Plant): All areas of plant and systems that are not included in Nuclear Island scope.

Base Construction Cost: The base construction cost (BCC) is the most likely plant construction cost based on the direct and indirect costs only. This cost is lower than the total capital investment cost (TCIC) because cost elements such as owner cost, supplementary cost and financial cost are not included. Direct costs are those costs directly associated with an item-by-item basis with the equipment and structures that comprise the complete energy plant, fuel cycle facility, module fabrication factory, or end-use plant. Indirect costs are expenses for services applicable to all portions of the physical plant. These include field indirect costs, design services, engineering services, Architect Engineer (A/E) home office engineering and design services, field office engineering and services, and construction management services. Reactor or other factory equipment manufacturer home office engineering and services are included in separate detail for appropriate accounts 35-38.

Baseline Cost: Refers to the initial costs developed for the subject plant, prior to validation and any subsequent cost adjustments.

Baseline Plant: Refers to the initial design of the subject plant before optimization and cost/benefit revisions.

Category: Refers to grouping of commodities that are common to a design discipline or lead craft, such as Concrete, Structural, Architectural, Civil, Mechanical, Piping, Instrumentation, or Electrical.

Category Wage: A composite cost per hour of the mix of crafts involved in all construction activities for the commodities that are included in the category of work. This composite cost per hour simplifies the estimating process and is based on actual construction experience for the percentages of crafts involved in each category of work

COA Detail: Describes a summary of plant components common to a system, facility, or function.

Commodity: A component detail of Category, such as Concrete Category consisting of commodities Formwork, Rebar, Embeds, and Structural Concrete.

Common Plant Facilities: Common plant facilities are those systems, structures, and components that provide common support to the operation at a new energy plant site and include such facilities as administration building, provisions for refueling, general warehouse, water supply, general fire systems, energy distribution, cooling water intakes, dry storage, civil and engineering offices, etc. These common plant facilities may be sized to be shared by other plant units added subsequently.

Constant Money: Constant money cost is the cost for an item measured in money that have a general purchasing power as of some reference date, e.g., January 1, 2001. Because inflation is associated with the erosion of the purchasing power of money, constant money analysis factors out inflation. In the Generation IV economic analyses carried out using the present guidelines only constant money costs will be considered. (See also Real Cost of Money).

Construction Module: A construction module is a free standing, transportable pre-assembly of a major portion of the plant, or a complete system or sub-system of the unit. A construction module may be a pre-assembly of a single system or portion thereof, or may contain elements of all the systems that exist in a given location in the plant. A construction module might contain parts of the building structure. A construction module might be assembled in a factory, shipped to the plant site, and installed in the plant (perhaps after minor assembly and/or linking). In some cases this might be an entire reactor island structure, i.e., a "reactor module." The direct costs for modules should contain within them their share of the manufacturing costs, including the fair burden of the cost of operating the factory where they are manufactured. If not, the factory-related costs must be accounted for elsewhere.

Construction Supervision: Refers to field non-manual personnel engaged in direct supervision of construction activities such as superintendents and field engineers.

Contingency: Contingency is an adder to account for uncertainty in the cost estimate (see Section 6.3 and Appendix A). Contingency includes an Allowance For Indeterminants (AFI) and should be related to the level of design, degree of technological advance, and the quality/reliability pricing level of given components (see Section 7.3). Contingency does not include any allowance for potential changes from external factors, such as changing government regulations, major design changes or project scope changes, catastrophic events (*force majeure*), labor strikes, extreme weather conditions, varying site conditions, or project funding (financial) limitations. Contingencies can be also applied to the interest during construction (IDC) and the capacity factor (CF) to account for uncertainty in the reactor design/construction schedule and reactor performance respectively.

Cost Component: Usually a detail component of a COA, such as Reactor vessel in a Nuclear Steam Supply COA; it can be a pump or piping components in a heat transfer system account detail. Includes cost elements for equipment, labor and materials.

Cost Element: Refers to cost details separated to Equipment, Labor, or Materials.

Cost Factor: Calculated resultant factor that relates a reference plant cost detail for the ratio of parameters between the reference plant and subject plant.

Cost Factor Exponent: Consideration of "size benefit" or common costs reflected in the cost of similar equipment, facility, or system with different ratings, capacity, or other suitable parameter. It is usually applied against the ratio of parameter values.

Craft Mix: Refers to the percentages of crafts involved in the performance of construction work for a category of work. As an example, "concrete" category includes: carpenters for formwork, iron workers for the rebar, laborers for actual placement of concrete and general assistance, as well as operating engineers for concrete pumps, cement finishers and other support craft such as electricians to monitor embedded conduits during concrete placement.

Craft Wage: Refers to individual craft wage determination including all costs such as wages, fringe benefits, premium costs, travel or living allowance, apprentice allowance, union dues, as well as employer's costs, such as insurance, and taxes. It excludes other allowances, such as small tools.

Crew Wage: Refers to a mix of wage rates calculated for a single craft crew, comprising of journeymen, apprentices, foremen, and general foremen.

Deployment Costs: Costs of developing a standard design and licensing it. These are considered part of FOAK costs and are distinct from R & D costs. These are non-recurring costs for subsequent plants and may be amortized over all the plants prior to NOAK plant (See Figure 1.1).

Deployment Phase: Refers to the period when all standard design and other plant data are generated to support commercial application of the standard plant. During this period are incurred all non-recurring costs that are required for the FOAK plant and will not be needed for any subsequent identical plants in a series.

Design Services: Refers to services performed offsite or onsite to produce all design documents and calculations required to construct the plant. For a standard plant with certified design and pre-licensed, the services are limited to those required to adopt the standard plant design for the specific site conditions. Those services include engineering and other support services, such as administrative, procurement and project control personnel, and their cost include salaries, office space, office furniture, office equipment, supplies, communications, travel and other labor related costs. Fees for the services are included in "62" account.

Direct cost: All costs that are identifiable to construction of permanent plant, excluding support services such as field indirect costs, construction supervision and other indirect costs (See also Base cost).

Direct Labor: Refers to construction crafts involved with construction activities that are identifiable to permanent plant, rather than general support activities such as site clean-up. It includes truck and crane drivers delivering equipment to permanent locations and all work operations that are identifiable to permanent plant, such as equipment maintenance or construction testing prior to plant startup.

Discount rate: In the context of the present guidelines, discount rate will be taken as equal to the real cost of money. Comparison calculations are to be performed for 5% and 10% discount rates. See definition for "real cost of money (r)".

Economic life: The period of commercial operation over which capital costs are recovered. This default value adopted in the EMWG calculation tool is 40 years but it may be modified by the user. The economic life usually will differ from the licensed lifetime as well as from the expected technical lifetime but should in no case exceed one of those.

Escalation rate: The rate of cost change. This rate can be greater than or less than the general inflation rate, as measured by the Gross Domestic Product Implicit Price Deflator. For Generation IV cost estimation, it will be assumed to be zero, unless otherwise justified. Escalation of reference plant costs that are expressed in values prior to Jan 2001 pricing basis are to be adjusted based on appropriate indices. See also Table 4.11 Escalation adjustment factors.

Equipment: Equipment for reactors includes all manufactured items ordered and delivered to a site, and used in construction. Such items may be procured on a design and build contract from qualified vendors, wherein design responsibility belongs to the seller (vendor) or is maintained by the buyer or purchasing agent on a "build-to-print" basis. To facilitate top-down estimating techniques, only process related equipment costs will be categorized as equipment cost. Non-process related equipment such as HVAC, plumbing, lifting or maintenance equipment, large pipe and valves, electrical and control equipment is to be classified as material costs.

Equipment module: An equipment module is a pre-packaged and site delivered (skid-mounted, factory-assembled) package that includes (but is not limited to) equipment, piping, instrumentation, controls, structural components, and electrical items. Module types include Box Modules, Equipment Modules, Structural Modules, Connection Modules, Electrical Modules, Control System Modules and Dressed Equipment Modules. These Modules are applicable to both the Nuclear and Balance of Plant, including support buildings. The same definition applies for equipment modules in fuel cycle, end-use, or module factory facilities.

Factory (manufacturing facility) FOAK costs: These FOAK costs include the development of manufacturing specifications, factory equipment, facilities, startup, tooling, and setup of factories that are used for manufacturing specific equipment for the nuclear energy system. These costs can be minimized if existing facilities are used for module production, which might not be dedicated or even its primary use application (e.g., a shipyard or any other factory that already builds modules for other industries or units). For a new modular nuclear energy plant, the new module fabrication factory might be considered a FOAK cost and included in module prices. If these costs are to be spread over a production run (or fleet size), then the cost should be estimated on that basis, and the number of plants or production needed to recover the factory costs defined. The module prices are in the unit/plant costs and as such, the price should be amortized in the LUEC or product cost over some number of modular reactors produced over its projected lifetime. The capital cost of the modules must amortize the module factory capital costs plus the normal annual production (operating) costs for the factory. For a pre-existing factory it is assumed that the price of the modules includes a fair share of any factory operating and capital recovery costs (overheads).

First commercial plant costs: The first commercial plant is the first standard plant of a particular type that is sold to an entity for the purpose of commercial production of electricity and/or other products. The costs include all engineering, equipment, construction, testing, tooling, project management, and any other costs that are repetitive in nature. Any costs unique to the first commercial plant, which will not be incurred for subsequent plants of the identical design, will be identified and broken out separately as FOAK plant costs. The "learning" process for this first plant will reflect its first commercial plant status and not be the average over a larger number of later plants. See Figure 1.1.

Fleet size: Refers to size or capacity of same type of plant for considerations of sizing support facilities such as fuel fabrication or reprocessing. It has been standardized to a 32 GWe capacity for the purpose of Generation IV nuclear energy system cost estimates.

FOAK plant costs: These are FOAK costs necessary to put a first commercial plant in place that will not be incurred for subsequent plants. Design and design certification costs are examples of such costs. See Figure 1.1.

Force account: Construction Labor Force account involves the direct hiring and supervision of craft labor to perform a construction activity by a prime contractor, as opposed to the prime contractor hiring a subcontractor to perform these functions.

Indirect cost: Consists of all costs that are not directly identifiable with specific permanent plant, such as field indirect, construction supervision, design services, and PM/CM services (See also "Base cost").

Industrial grade construction: Industrial grade construction means construction practices that conform to generally-accepted commercial requirements, such as those required for fossil-fired plant construction. Industrial grade construction could be used for end-use facilities, such as hydrogen production. A module factory could also use industrial grade construction for the production of some modules (See also "Nuclear-safety grade").

Indirect Labor: Refers to construction craft labor involved in performing support activities that are not directly identifiable to permanent plant; it includes temporary facilities, temporary services, warehousing, construction equipment maintenance, security services, etc.

Inflation rate: The rate of change in the general price level as measured by the Gross Domestic Product Implicit Price Deflator. The inflation rate is assumed to be zero in constant money based studies.

Initial core cost: The cost of the materials and services required to provide the first loading of fresh fuel assemblies to the reactor(s). In the present guidelines, the initial core costs will be considered part of the total capital investment that is amortized in the capital component of LUEC. The fuel cycle algorithms discussed in Chapter 8 are used to calculate the initial core costs.

Interest During Construction (IDC): IDC is the interest accrued for up-front cost financing, i.e., it is accrued to the end of construction and plant startup (See Section 7.2).

Island: Refers to Nuclear Island or Turbine Island consisting of multiple buildings or facilities such as Nuclear Island comprising Reactor Building, Containment, Fuel Handling, etc.

Large monolithic plant: A large monolithic plant is an energy plant consisting of a large nuclear steam supply system (NSSS) having an energy, and/or product output. In some instances, a plant of this size is referred to as an integrated plant or stick-built plant. All today's PWRs and BWRs are considered monolithic plants.

Levelized Unit of Energy Cost (LUEC): For the "standard plant" it includes costs associated with non-generic licensing, capital investment, operation and maintenance of the energy plant, owner's costs, ongoing refurbishment, fuel, waste disposal, and decommissioning the plant at the end of life, and may include revenue offsets due to byproduct production. Typically the four components of LUEC reported are: the capital component (recovery of capital cost over economic life); the production or non-fuel O&M component; the fuel component; and the decommissioning (D&D) component. Chapter 9 discusses the calculation of LUEC. Normally this cost does not have R&D and demonstration (prototype) cost embedded in it. If the FOAK plant is a commercial plant, it would have some FOAK costs, such as generic design and design certification, recovered in the LUEC. The remaining recoverable costs would be recurring “standard plant” costs. For a power plant generating electricity LUEC is the “Levelized Unit of Electricity Cost”.

Materials: Materials include field-purchased (site material) and/or bulk commodity items, such as lumber, concrete, structural steel, and plumbing items. All piping is a materials item. Also all wire and cable and raceways are material items, including those in building service power systems. Also included is non-process related equipment such as HVAC, cranes, hoists, doors, plumbing, sewage treatment, electrical and control equipment, etc. To facilitate top-down estimating techniques, only process related equipment is to be classified as equipment cost.

Modular unit: A smaller capacity unit that is constructed on site with benefits from modularity effects.

Modularity: Generic term, representing a comparative use of many standardized smaller units, with a lesser number of larger units, for the same installed capacity (MWe).

Modularization: Process of converting the design and construction of a monolithic plant or stick-built scope to facilitate factory fabrication of modules for shipment and installation in the field as complete assemblies.

Module: Usually refers to a packaged, fully functional assembly for use with other standardized assemblies to obtain a system. See also Construction Module and Equipment Module.

Monolithic plant: refers to a plant constructed in field without extensive use of modules. It is also referred to as a “stick-built” plant.

Multi-unit plant: A plant consisting of more than one production unit.

Nominal currency/dollars: The reference currency adopted by default in the Guidelines is the US dollar. Nominal dollar cost is the cost for an item measured in as-spent dollars and includes inflation. Nominal dollars are sometimes referred to as “current” dollars, “year of expenditure” dollars, or “as spent” dollars. The methodology in this document uses real dollars rather than nominal dollars.

Nominal cost of money: The nominal cost of money is the percentage rate used in calculations involving the time value of money containing an inflation component. It explicitly provides for part of the return on an investment to keep up with inflation.

Non-recurring costs: Common costs incurred prior to commercial operation of FOAK that are part of the program costs and are to be shared by all plants. They exclude costs that are required for each plant such as site licensing and site specific design. These costs will be amortized over all the plants prior to NOAK plant.

Nth-Of-A-Kind (NOAK) plant cost: The NOAK plant is the nth-of-a-kind or equilibrium commercial plant of identical design to the FOAK plant. NOAK plant cost includes all engineering, equipment, construction, testing, tooling, project management, and any other costs that are repetitive in nature and would be incurred if an identical plant were built. The NOAK plant cost reflects the beneficial cost experience of prior plants. NOAK plant is defined as the next plant after the unit that achieves 8.0 GWe of capacity (See Figure 1.1).

Nuclear Island (NI): Refers to the part of plant containing a majority of nuclear related equipment and systems. Typically it consists of containment, reactor building, fuel handling building, etc.

Nuclear-safety grade: Refers to construction practices that satisfy the Quality Assurance and other requirements of national licensing (e.g., 10CFR50, Appendix B in the United States). Both reactor and fuel cycle facilities will require some nuclear grade construction.

Overnight cost: The (total) overnight cost (OC) is the base construction cost plus applicable owner's cost, contingency and first core costs. It is referred to as an overnight cost in the sense that time value costs (IDC) are not included, i.e., as if the plant were constructed "overnight" with no accrual of interest [OC = TCIC – IDC]. The total overnight cost is expressed as a constant dollar amount in reference year dollars. Commissioning and first core costs are included in the overnight cost for this study, which is not usually the case for conventional reactor estimates. This expanded definition is used to reflect the fact that the first core must be paid for before revenues are accrued. Allowing all "up-front" costs to be combined into one lump sum term prior to calculation of the IDC simplifies the algorithms used to calculate the LUEC.

Owners Cost: Refers to cost components that are typically Owner responsibility including scope of COA 40 - Capitalized operations, 50 - Capitalized supplementary costs, and 60 - Capitalized financial costs.

Owner's discretionary items: For a power plant these include the switchyard (after the bus-bar) and transmission system, the hydrogen distribution system, and fuel or module transportation equipment. These are not included in the LUEC but may be included in Owners cost for a specific project.

Parameter: Refers to a measure of system or equipment rating, capacity, weight or other measure that represents a basis for calculation of cost adjustment factors.

Plant: Complete project, comprising power generation plant alone or in conjunction with other plants, such as hydrogen production or desalination.

PM/CM Services: Refers to Project Management (PM) and/or Construction Management (CM) services performed onsite or offsite for management of total project; includes project manager and staff, procurement buyers and contract administration, project cost engineers, project schedulers, first aid, medical, administrative, payroll, accounting, clerical, labor relations, security, etc., and salaries, salary related costs, office equipment, supplies and fees for the services.

Power unit: A power unit (sometimes called a "building block") is a combination of one or more reactor modules and associated electrical generation equipment and structures that represent the smallest unit for commercial electrical generation. Power units may be duplicated for capacity expansion.

Process Equipment: Refers to equipment items that are required to perform the design system function for all physical processes. Equipment for services systems such as HVAC, ventilation, plumbing, potable water, sewer, cranes, hoists, etc are categorized as materials. This segregation facilitates top-down estimating techniques whereby process equipment costs are basis for application of bulk factors to estimate piping, electrical and other commodities.

Productivity: Refers to a measure of labor effectiveness relative to a standard. Actual job hours divided by standard hours for the same work scope represents a productivity factor for the project. Standard hours are calculated by multiplying the quantity of work times the standard unit hours for the work. Usually it is expressed by category of work, such as concrete, piping or electrical category. Also it can be calculated for total direct, indirect or total craft labor as well as craft supervision or total field non-manual.

Prototype-of-a-Kind (POAK): Costs specific to any prototype plant. These include prototype-specific design, development, licensing, construction, testing, and operation of the prototype to support the demonstration of the system or concept (this prototype may assist, but does not meet or satisfy standard plant design certification). These costs are separate from FOAK (see Chapter 3) and are not amortized within the LUEC.

Research, Development and Demonstration (RD&D) costs: Costs associated with material, component, system, process, and fuel development and testing performed specifically for the particular advanced concept. These costs are often borne by governments or by industry consortia, and are recovered depending on national practices. In the present guidelines, RD&D costs are not distributed into the cost of electricity production. However, their sum for each system is an important figure of merit for GIF decision makers. Chapter 3 contains a generic list of these costs for the reactor and its fuel, including prototype costs (See deployment cost definition for other "non-standard" costs and Figure 1.1).

Reactor module: A reactor module is a single reactor and that portion of the nuclear island that is duplicated, and capable of criticality when loaded with fuel as an integral part of a building block of energy production. It is delivered to site as a prefabricated component, without necessarily requiring additional construction. (See also equipment module).

Real cost of money (r): The real cost of money is the percentage rate used in calculations involving the time value of money when the inflation component has been removed (constant money calculations). Calculations using the real cost of money assume that the money maintains a constant value in terms of purchasing power, and, thus, no return on investment (ROI) is needed to cover inflation. For consistency of comparisons, cost estimates carried out with the present guidelines should be made for two rates: 5% and 10%.

Reference Plant: A collection of information, including of plant description, plant characteristics and design data (with ratings and parameters) and cost data that represent a similar process, system, facility, or equipment component. The data is used for cost development of a plant cost component or COA detail.

Reference plant costs: These are the basis for estimating baseline plant costs in the absence of a fully worked up (or proven) cost for a commercial unit (i.e., a surrogate basis for estimating total plant cost and cost differences). The reference plant is not part of the overall project, but rather a benchmark from which to begin costing the baseline subject plant. Obtaining this information may involve many months of labor (See Chapter 4 on top-down cost estimation using reference plant costs).

Single-unit plant: A stand-alone commercial energy plant consisting of a single unit and all necessary common plant facilities is referred to as a single-unit plant. This is the smallest unit of energy capacity normally sold to a customer, such as a utility.

Specific cost: Total cost divided by the net capacity (net kWe) of the plant.

Standard fuel facility design costs: These costs include the design and engineering of facility and equipment, proof testing of equipment, and licensing for any concept. Standard fuel facilities may be either integral to the energy plant, central, or both. These costs should be amortized into the fuel cycle costs rather than the reactor costs.

Standard Hours: Calculated hours of construction quantity work scope times the standard unit hours. The ratio of project hours divided by standard hours for the same work scope is a measure of project productivity.

Standard plant design costs: Costs associated with the engineering and engineering support functions for the design of the standard plant. These are a FOAK non-recurring cost for the first commercial standard plant. These do not include the site-specific engineering costs that are associated with all standard plants.

Standard plant licensing costs: Costs associated with licensing related activities performed to establish that the design of the standard plant is adequate for obtaining a license. In the United States, it includes the design and analysis of prototype tests necessary for certification, coordination with NRC, and preparation of documents required for certification of the standard plant design. These are a FOAK non-recurring cost for the first commercial standard plant. These do not include the site-specific engineering costs that are associated with all standard plants.

Standard Unit Hours: A set of unit hour rates per quantity of work scope. Usually, serves as a basis for calculation of standard hours for a project before application of a productivity factor for a specific project or site.

Station: One or more plants on a single site. Each plant can be one or more units.

Subject plant: A specific type of plant that is being developed by the individual system designer and is being estimated.

System Designer: Refers to the organization performing the design of the specific type of plant.

Technology development costs: See RD&D costs.

Transition period: The period from the start of the construction of the FOAK to the end of construction of the last plant before the NOAK plant.

Transition-period plant-specific capital costs: The capital costs for the transition plants (2OAK, 3OAK, etc.). These costs exclude any non-recurring FOAK costs and include costs for manufacturing of factory equipment, site construction, site-specific engineering, and home office construction support. The transition in costs from the first to NOAK commercial plant and the beneficial cost effects of serial manufacturing and construction should be documented, for guidance, see Appendix E.

Total Capital Investment Cost: The Total Capital Investment Cost (TCIC) is an all inclusive plant capital cost (or lump-sum up-front cost) developed for the purpose of calculating the plant LUEC ($/MWh), the unit cost of a fuel cycle material or service (such as $/kg U), end-use product (such as $/kg H_2), or a factory-fabricated module or equipment item (such as $/module). This cost is the base construction cost plus contingency, escalation (zero for these studies, unless justified), IDC, owner's cost (including utility's start-up cost), commissioning (non-utility start-up cost), and initial fuel core costs (for reactor). Since constant dollar costing will be used in these studies, escalation and inflation are not included.

Unit: See also single-unit plant. A set of facilities and systems to produce electrical energy and/or other product such as hydrogen or desalinated water as one set of energy source and conversion or production systems, such as reactor and turbine generator systems.

Unit Equipment Cost: Total costs associated with a piece of process equipment. Usually includes vendor engineering, testing, certification, packaging for shipment, local delivery, warranty, and recommended construction spare parts.

Unit Hours: Sum of all construction craft time spent for installation of equipment or commodity divided by the unit of quantity for the equipment or commodity, including delivery from storage, installation, craft time for inspections and construction testing before plant startup.

Unit Material Cost: Total costs associated with a bulk commodity per unit of measure. For example, piping commodity includes vendor fabrication into spools, as well as costs of pipe supports, hangers, and accessories associated with installation of the pipe. Unless separately identified in cost details, includes welding or mechanical joints, non-destructive testing, hydro testing, insulation, penetrations, painting, line number identifications, etc. Similar inclusions also apply for other commodities such as cable tray, conduit, structural steel, HVAC ducting etc.

Figure 1.1 Temporal relationships of RD&D, deployment, and standard plant costs

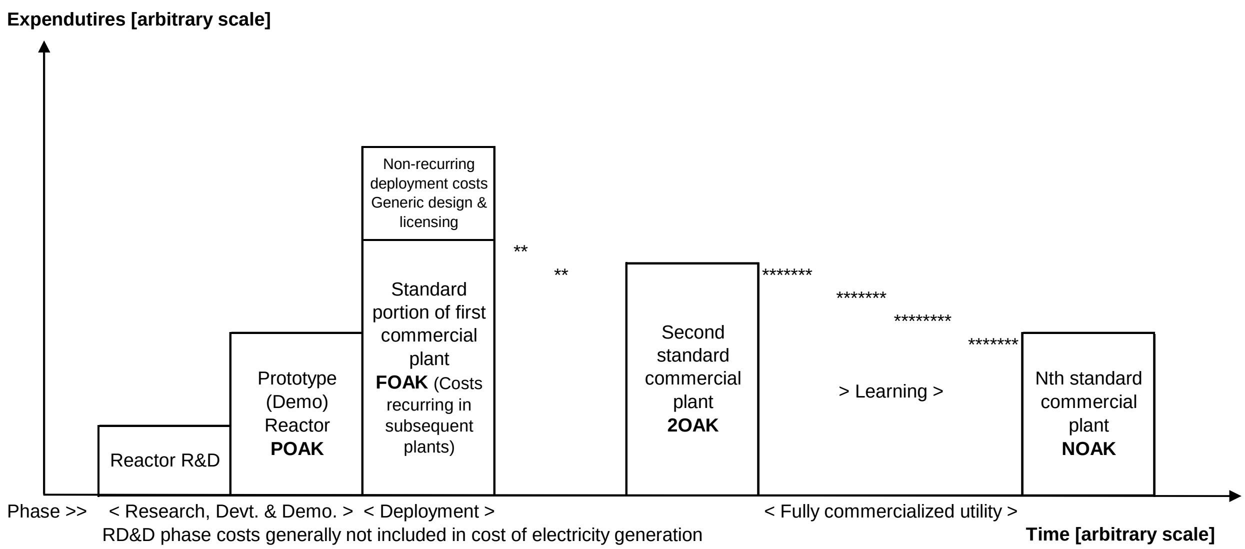

Figure 1.1 shows the relationship in time between some of the cost categories defined above and which costs are included in the cost of electricity. It should be noted that the horizontal and vertical scales of the graph are illustrative only and not scaled to real time and expenditures.

1.5 The GIF Code Of Account (COA)

The IAEA has developed a comprehensive account system capable of addressing a spectrum of capital, fuel cycle, and O&M costs, from a complete Nuclear Energy Plant (NEP) down to individual systems and components. Since the accounting system has a high degree of flexibility, it can be used with all types of reactors, single or dual-purpose energy plants, and various contract/deployment approaches. This account system was developed by IAEA to assist developing countries in the bid evaluation process for nuclear energy plants to be constructed with the help of reactor vendors, A/Es, and constructors from outside mostly industrialized countries. The account system and the bid evaluation process are fully documented in an IAEA report (IAEA, 2000). In order to meet the needs of the EMWG and the system designers/estimators, some revisions were made to the IAEA account system to create a GIF COA. The revisions are in two areas:

- Many of the IAEA categories will only exist in very high level of detail, "bid-quality" final estimates. These categories will be included in summary level accounts.
- The two-digit direct cost categories (Accounts 21-29) in the IAEA account system include equipment only, relegating installation labor and materials (commodities) to other accounts. Unfortunately, this hides data that should be presented at the sub-system (2-digit) level. As in the original ORNL/United Engineering EEDB, direct costs include equipment, direct installation labor-hours, and commodities for installation such as wire, concrete, etc. (It should be noted that this document presents COA below the 2 digit level, particularly in Appendix F. This additional detail is meant to assist the development teams in detailed cost estimates approaching the Bottom Up method. For reporting cost estimates, the EMWG advocates only a 2 digit COA to protect proprietary information.)

1.5.1 Nuclear Energy Plant Capital Investment Cost Account System

The investment costs for a complete nuclear energy plant or parts of it, include the costs of engineering, construction, commissioning, and test run (considered part of "start-up" or commissioning) to commercial operation. The base costs include costs associated with the equipment, structures, installation, and materials (direct costs), as well as field indirect, design services, construction supervision and PM/CM services (indirect costs). In addition to the base costs there are supplementary costs (such as initial core and spare part costs), financial costs (such as IDC), owner's costs (including the owner's capital investment, services costs, and related financing costs), and contingency. The Total Capital Investment Cost (TCIC) is the cost of building the plant and bringing it into commercial operation. The breakdown adopted in the guidelines is as follows:

10 – Capitalized Pre-construction costs
<u>20– Capitalized Direct Costs</u>
DIRECT COST
<u>31-34 – Field indirect costs</u>
TOTAL FIELD COST
<u>35-39 – Capitalized Field Management Cost</u>
BASE CONSTRUCTION COST
40 – Capitalized Owner Operations
<u>50 – Capitalized Supplementary Costs</u>
OVERNIGHT CONSTRUCTION COST
<u>60 – Capitalized Financial Costs</u>
TOTAL CAPITAL INVESTMENT COST (TCIC)

The GIF code of account is a numerical system designed to provide cost information for any component of a particular project, from design, layout and procurement of equipment, to the final installation. At the two-digit level it can be applied to either bottom-up or top-down cost estimates. At the three-digit and four-digit level and above, a bottom-up estimate is usually required to "fill in the blanks." The GIF code of account is primarily a system of cost accounts and is based on a physical subdivision of the project. However, as a project matures, it may also be convenient to use it for other purposes, such as filing, drawing and document control, and numbering and coding of equipment. The advantages are that this system eliminates the need to develop separate systems for each purpose, so that only one system needs to be learned, and provides a common language for the whole project. At two-digit level, the subsystem category names should be applicable regardless of the reactor system or technology described.

At the three-digit level commonality of account descriptions between technologies begins to disappear. Chapter 5 considers definitions at the three-digit level for use in bottom-up estimating. In the GIF TCIC account system, pre-construction costs are allocated to accounts 10, direct costs to accounts 20, capitalized indirect services to accounts 30 and the totals of these accounts 10 thru 30 representing base construction costs of the plant. Capitalized owner costs are allocated to accounts 40, and supplementary costs to Accounts 50. The subtotal at this level (accounts 10 thru 50) represents the plant overnight construction costs. Remaining capitalized costs for financing are allocated to accounts 60 for a Total Capital Investment Cost (TCIC).

It should be noted that the IAEA account system was created for evaluating highly detailed bids for proposed commercial nuclear energy plants. Therefore, for GIF purposes and simplicity in the present guidelines, all the IAEA categories are not used. Omitted accounts are noted.

Table 1.2 GIF power generation plant COA

Account number	Account title
1	Capitalized Pre-construction Costs(CPC)
11	Land and Land Rights
12	Site Permits
13	Plant Licensing
14	Plant Permits
15	Plant Studies
16	Plant Reports
17	Other Pre-construction Costs
18	Other Pre-construction Costs
19	Contingency – Pre-construction Costs
2	Capitalized Direct Costs(CDC)
21	Structures and Improvements
22	Reactor Equipment
23	Turbine-Generator Equipment
24	Electrical Equipment
25	Heat Rejection System
26	Miscellaneous Equipment
27	Special Materials
28	Simulator
29	Contingency–Direct Costs
DIRECT COST	
3	Capitalized Indirect Services Cost (CIC)
31	Field Indirect Costs
32	Construction Supervision
33	Commissioning and Start-up Costs
34	Demonstration Test Run
TOTAL FIELD COST	
35	Design Services Offsite
36	PM/CM Services Offsite
37	Design Services Onsite
38	PM/CM Services Onsite
39	Contingency – Support Services
BASE COST	
4	Capitalized Owner Cost (COC)
41	Staff Recruitment and Training
42	Staff Housing
43	Staff Salary Related Costs
44	Other Owner Capitalized Costs
49	Contingency – Operations Costs
5	Capitalized Supplementary Costs(CSC)
51	Shipping and Transportation Costs
52	Spare Parts
53	Taxes
54	Insurance

Account number	Account title
55	Initial Fuel Core Load
58	Decommissioning Costs
59	Contingency Supplementary Costs
OVERNIGHT COST	
6	Capitalized Operations
61	Escalation
62	Fees
63	Interest During Construction
69	Contingency – Financial Costs
TOTAL CAPITAL INVESTMENT COST(TCIC)	

Table 1.2 presents an outline of the GIF account system used in preparing a summary of the TCIC and indicates the modifications proposed for the present guidelines. Initial fuel costs have been added in account 55 and heavy water costs are included in account 27.

Account 21 as defined by the IAEA includes all costs for buildings and structures, such as the bulk material and the associated engineering and documentation for construction work at the site. It is important to note that Accounts 22–27 as defined by the IAEA include costs of equipment manufacture, materials for components and systems, and the engineering and documentation associated with the manufacturing process in the factory. Pre-installation assembly and site fabrication costs of some of the main components can be entered under Accounts 22 and 23, where appropriate. Under the IAEA system general site construction, installation labor and field supervision costs are included in Accounts 34–39. (Under the old EEDB system of accounts some of this was in the “9X” series.) Engineering and design work performed by the supplier and/or A/E at the home office(s) must be considered under Account 30. For Generation IV estimates we will include installation and construction labor for a particular subsystem, such as Account 22 (reactor plant equipment) within Account 22 and not in IAEA Accounts 35 or 36 (where all labor for all subsystems is collected). This allows for better insights into subsystem total costs and conforms to the EEDB approach used in previous Guidelines. This segregation of costs and cost components facilitates top-down, cost ratio estimating techniques.

Appendix F provides a full dictionary of the GIF Code of Accounts.

1.5.2 Nuclear Fuel Cycle Cost Account System

The nuclear fuel cycle costs include the costs of uranium supply, conversion, and enrichment; fuel fabrication; transport; intermediate storage and final disposal of spent fuel (for the direct disposal option). For the reprocessing option, the costs also include those for chemical reprocessing associated with waste management, along with storage and final disposal of high-level radioactive waste, as well as any credits realized through the sale and use of uranium, plutonium, heavy water, or other materials. It will be necessary to revise this accounting system for innovative fuel cycles not considered by IAEA when its code was prepared.

Table 1.3 presents an outline of the GIF code of account used in preparing a summary of the nuclear fuel cycle costs for light water and heavy water reactors. Accounts 150 and 151 include heavy water supplies and services. These are to be used only if they are included in the fuel costs; otherwise they can be included as capital investment costs in Account 27. Accounts 160 and 161 (for the supply of heavy water replacement quantities and related services), can be included in the O&M costs.

Table 1.3 Structure of the GIF nuclear fuel cycle COA

Account Number	Account title
10X	Fuel assembly supply, **first core (covered as Account 55X in TCIC above)**
101	1st Core Uranium supply **(See Chapter 9 algorithms, show in Account 551)**
102	1st Core Conversion **(See Chapter 9 algorithms, show in Account 552)**
103	1st Core Enrichment **(See Chapter 9 algorithms, show in Account 553)**
104	1st Core Fuel assembly fabrication **(See Chapter 9, show in Account 554)**
105	1st Core Supply of other fissionable materials **(e.g., plutonium) (Account 555)**
11X	Services, **first core (include in Account 55)**
111	Fuel management (U, Pu, Th) **(ignore for early estimates)**
112	Fuel management schedule **(ignore for early estimates)**
113	Licensing assistance **(ignore for early estimates)**
114	Preparation of computer programs **(ignore for early estimates)**
115	Quality assurance **(embed in fuel fabrication cost, Account 554)**
116	Fuel assembly inspection **(embed in fuel fabrication cost, Account 554)**
117	Fuel assembly intermediate storage **(embed in fuel fabrication. cost, Account 554)**
118	Information for the use of third party fuel **(ignore for early estimates)**
12X	Fuel assembly supply for **reloads (calculate as equilibrium reloads and annualize costs, see Chapter 8)**
121	Uranium supply **for reloads** (**Calculate as per Chapter 8**)
122	Conversion **for reloads** (**Calculate as per Chapter 8**)
123	Enrichment **for reloads** (**Calculate as per Chapter 8**)
124	Fuel assembly fabrication **for reloads** (**Calculate as per Chapter 8**)
125	Supply of other fissionable materials **for reloads** (**Calculate as per Chapter 8**)
13X	Services, **reloads**
131	Fuel management **(ignore for early estimates)**
132	Fuel management, schedule **(ignore for early estimates)**
133	Licensing assistance **(ignore for early estimates)**
134	Preparation of computer programs **(ignore for early estimates)**
135	Quality assurance **(embed in Account 124)**
136	Fuel assembly inspection **(embed in Account 124)**
137	Fuel assembly intermediate storage **(embed in Account 124)**
138	Information for the use of third party fuel **(embed in Account 124)**
140	Reprocessing of irradiated fuel assemblies **(Calculate as per Chapter 8)**
141	Credits for uranium, plutonium and other materials **(Calculate as per Chapter 8)**
142	Final disposal of fuel assemblies (in the case of no reprocessing) **(Calc. as per Chapter 8)**
143	Final waste disposal (**Calculate as per Chapter 8**)
150	Heavy water supply, first charge **(include in TCIC Account 27)**
151	Heavy water services, first charge **(include in TCIC Account 27)**
160	Heavy water supply, replacement quantities **(include in O&M Account 810)**
161	Heavy water services, replacement quantities **(include in O&M Account 810)**
170	Financial costs of the nuclear fuel cycle **(ignore for early estimates)**
171	Financial costs of heavy water **(ignore for early estimates)**

1.5.3 O&M Cost Account System

The O&M costs include all non-fuel costs, such as costs of plant staffing, consumable operating materials (worn parts) and equipment, repair and interim replacements, purchased services, and nuclear insurance. They also include taxes and fees, decommissioning allowances, and miscellaneous costs. In addition, the costs of general and administrative support functions and the cost of providing working capital for plant O&M are included. Table 1.4 presents an outline of the GIF O&M cost account system.

Table 1.4 Structure of the GIF O&M COA

Account Number	Account title
7	Annualized O & M Cost
71	Operations and Maintenance Staff
72	Management Staff
73	Salary Related Costs
74	Operations Chemicals and Lubricants
75	Spare Parts
76	Utilities, Supplies, Consumables
77	Capital Plant Upgrades
78	Taxes and Insurance
79	Contingency Annualized O & M Costs
8	Annualized Fuel Cost
81	Refueling operations
84	Nuclear Fuel
86	Fuel reprocessing Charges
89	Annualized Fuel Costs
9	Annualized Financial Costs
91	Escalation
92	Fees
93	Cost of Money
99	Contingency Annualized Financial Costs

Appendix F provides a full dictionary of the GIF Code of Accounts. The G4Econs software makes use of the Code of Accounts for input and cost output display.

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2. STRUCTURE OF AN INTEGRATED NUCLEAR ENERGY ECONOMIC MODEL

2.1 Flow Diagram for an Integrated Nuclear Energy Economic Model

Figure 2.1 shows the proposed overall structure of the Integrated Nuclear Energy-Economic Model (INEEM) created by the EMWG.

Figure 2.1 Structure of the proposed INEEM

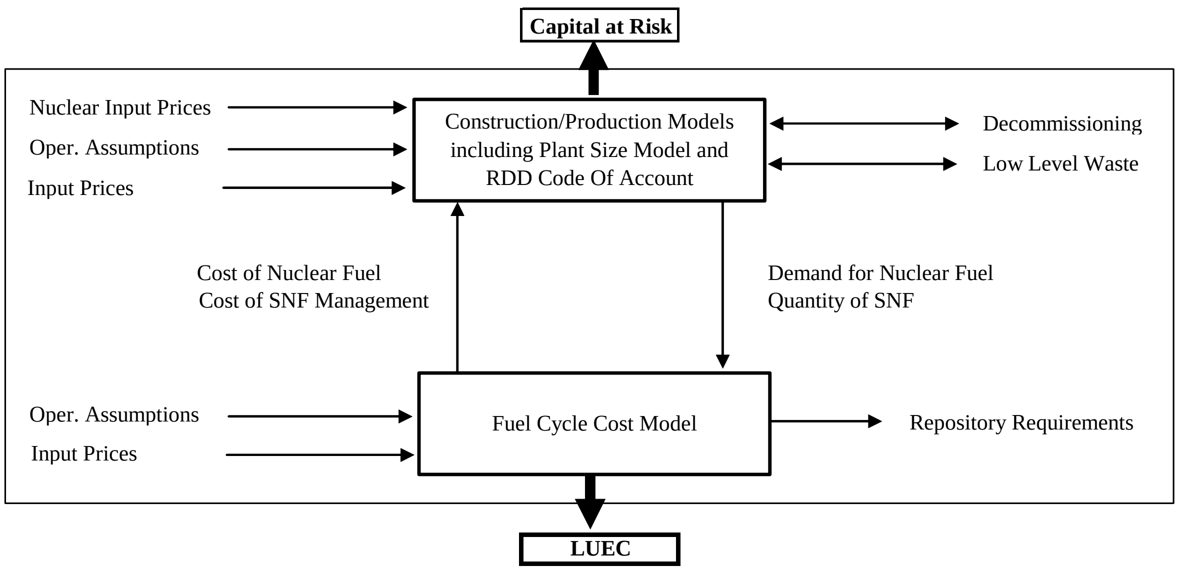


Figure 2.2 shows the structure of the model to calculate the construction and production cost components of the LUEC.

It should be noted that contingency is partitioned into three parts when calculating the LUEC. The first contingency is typically the one applied to the base cost and covers construction cost uncertainty. The second one, applied to the IDC term, covers the cost effect of construction schedule uncertainty. The third contingency is a factor applied to cover uncertainty in plant performance as measured by the capacity factor. Since unit cost is being calculated, this term covers the uncertainty in the denominator of the $/MWe figure-of-merit.

Figure 2.3 shows the structure and logic of the fuel cycle portion of the Integrated Nuclear Energy Economics Model. Chapter 8 discusses the fuel cycle in detail.

Figure 2.2 Structure and logic of the design/construction and production cost parts of the model

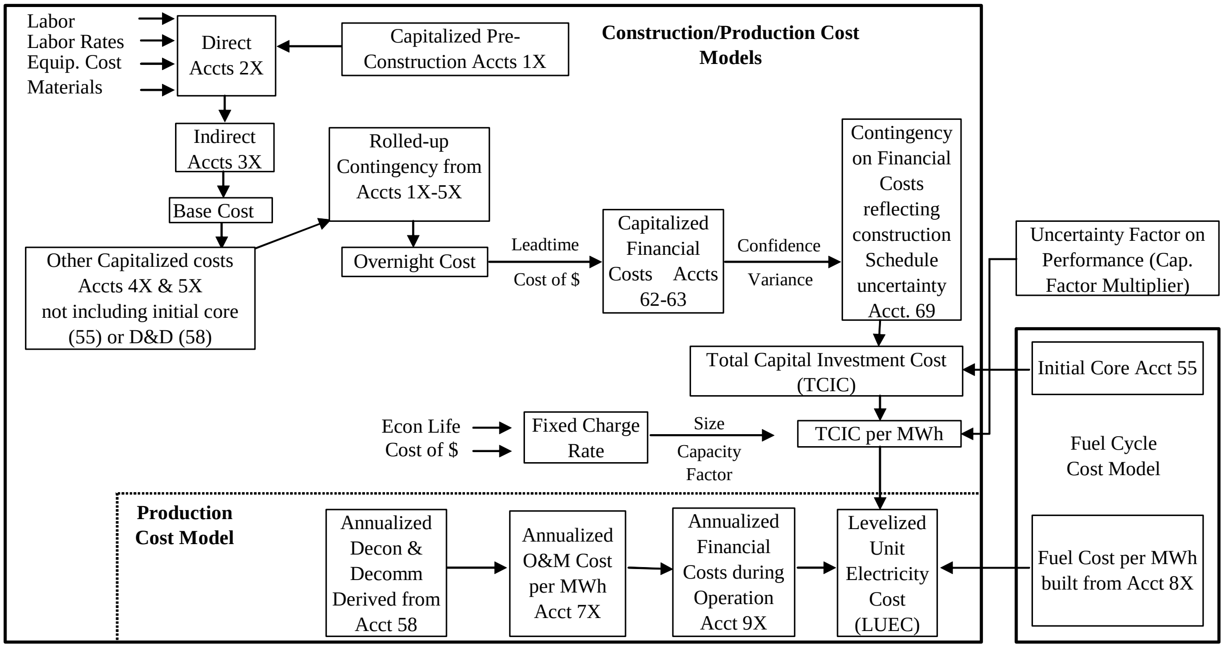
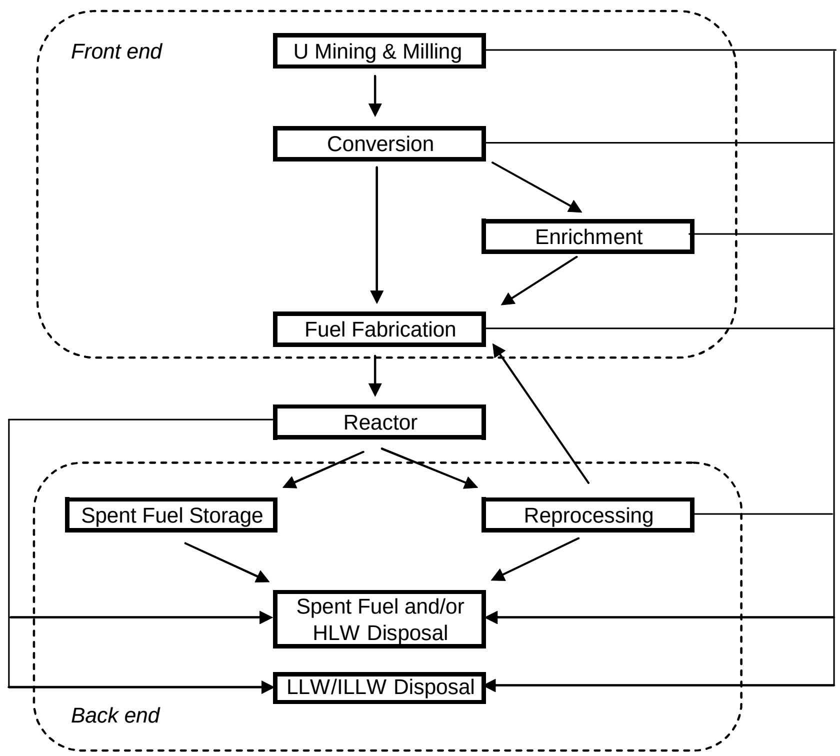


Figure 2.3 Structure and logic of the U-based fuel cycle part of model



2.2 Top-down Versus Bottom-up Cost Estimating

The models needed to assess the economics of Generation IV nuclear energy systems must be more than the arithmetical manipulation of dozens of two-digit level cost accounting categories and calculated figures of merit based upon the EMWG guidelines. They must be backed up by more detailed concept-specific cost estimates. This detailed estimating is the responsibility of the system development teams. The preparation of an estimate can take two paths: top-down or bottom-up, depending on the maturity of the concept, the financial resources available to the design/estimating team, and the type of scientific/engineering individuals on the system development team. These two paths are discussed below.

2.2.1 Bottom-up Estimating

This is the more familiar type of estimating applied to projects as they near construction. For large nuclear projects Architect/Engineering (A/E) teams generally perform bottom-up estimating in conjunction with a utility. The A/E prepares a detailed baseline design with layout diagrams for all major systems. This estimate is prepared from the bottom up, i.e., from very detailed items, such as equipment lists, commodity quantity estimates by take-off from drawings or direct from conceptual 3D design models ("bricks and mortar"). Unit prices and unit labor-hour rates are then applied to the estimated quantities, extended and summarized to the code of accounts for the direct cost elements. Project execution plans provide basis for detail estimates of the field indirect costs, together with the construction schedule for the time related field indirect costs. This process is often described as working from "engineering take-offs" and requires a staff of at least a dozen engineers and estimators, even at the conceptual design level. The thousands of detail items and activities are then organized into a Code of Accounts at least to the three-or-four digit level for all categories. Activities are often subdivided into a "Work Breakdown Structure" or WBS that conforms to the COA and task schedule. The scheduling activity is also at a high level of detail and requires the use of scheduling software, such as "Primavera" systems. For use in the EMWG models, the highly detailed 3 to 6 digit COA entries must be rolled up to the two-digit level. Other estimates, such as those for operations, would require similar rollups from highly detailed staffing and consumables information. As bottom-up estimating proceeds, cost contingencies decline (expressed as a percentage of base costs at a fixed confidence level, e.g., 80% chance that an overrun of the base cost plus assigned contingency will not occur). Chapter 4 defines the kinds of Base Cost categories that are used in this type of estimating. As expected, this method must be backed up by data, such as unit costs of labor, commodities, installation rates, construction labor-hour estimates, and siting requirements. Chapter 4 of this document presents typical values for these unit rates. Chapter 6 presents the process for bottom-up estimating.

2.2.2 Top-down Cost Estimating

For projects early in their life cycle, top-down estimating techniques can be used. It is likely that many of the Generation IV systems will use these methods, since these systems are at an early stage of development. At this stage, the design/development/estimating staff is usually small, and financial resources are limited. The first task is to develop a reference design to which cost estimating techniques can be applied. The cost estimating part of this task generally is accomplished by considering the costs of systems and equipment used for similar projects and then scaling the system or equipment upwards or downwards. As an example, one might start cost estimating work on the VHTR by scaling reactor plant equipment from a project for which detailed estimates are available, such as the General Atomics HTGR.

Auxiliary costs and indirect costs are often calculated with standardized factors or formulas. For example, calculating design costs as a fixed fraction, based on historical experience, of construction costs, can be done. With these formulas are sometimes found cost-scaling equations; however, at this time there exists no set of equations that can be used for all projects. These equations are equipment specific and must be developed by the designers and cost estimators working jointly. Several countries, including Argentina, Canada, and France, are using such an approach on advanced reactor design and estimating. Some of their work is discussed in Chapter 5. Despite its lack of cost detail, this method has the advantage that it can be used to optimize designs such that the lowest LUEC can be realized. Chapter 5 presents the process for top-down estimating.

2.3 Integration of Cost Estimating into the Design Process

Earlier Cost Estimating Guidelines were used to calculate the major cost figures-of-merit for a bottom-up reference or baseline design. Before the availability to designers of high-speed desktop computers and workstations, CADD tools, and data base systems, reactor system designs were nearly always fixed and completed before the detailed cost estimation process was initiated. Integration of nuclear core physics, thermal hydraulics, safety limits, etc., into one design was usually done manually. Value engineering was always used to guide the design process. However, it was unusual for cost estimating models or algorithms to be directly built into the engineer's design tools. Usually, cost estimating guidelines were not considered until the formal bottom-up cost estimating process.

With new computational and data management tools, it is now possible to integrate cost estimation directly into the top-down design process. This allows the possibility of LUEC and baseline capital cost optimization during design. For Generation I, II, and III reactor designs this procedure was not readily available. With the Generation IV design efforts there is opportunity for cost modeling to be directly integrated into the design process. One such costing process, used by AECL, is outlined in Appendix B.

The use of computer models integrating process science/engineering, performance, design, plant layout, cost scaling, cost figures of merit, and optimization is not new and has been used extensively in chemical process industries (Williams, 1984). DOE-NE used Oak Ridge developed FORTRAN-based models of this type extensively in the mid-1980s to evaluate uranium enrichment technologies. Improved optimization tools coupled with reactor models are now being used for reactor design (Nisan *et al*., 2003; Grinblat *et al.*, 2002). Cost estimating guidelines and "rules of thumb" are used to establish some of the scaling rules and calculation of figures of merit, such as LUEC. The "cost modules" use cost/size scaling equations for capital cost calculation and scaling relationships for variable costs within the O&M and fuel cost models. A model of this type was used for economic feasibility studies of the U.S. Atomic Vapor Laser Isotope Separation process and the Advanced Gas Centrifuge Enrichment process. If connected to single variable or multivariable sensitivity analysis software, such models can help the RD&D and deployment program identify those performance and cost parameters that have the most influence on projected unit cost, and therefore identify those parameters that should be given most priority in the RD&D program.

2.4 Figures of Merit of Interest in these Guidelines

A number of aggregated costs that can be calculated using the present guidelines are of high interest for GIF decision makers. These high level figures of merit are described below.

2.4.1 Costs to Research, Develop and Demonstrate the Generation IV Reactor System

These costs normally do not get factored into the cost of electricity (or other products); however, they represent a significant cost to the governments and/or industrial consortia that undertake RD&D of the various concepts. The decision makers need to know early the costs of these programs that could be in the hundreds of millions of US dollars before a demonstration unit is constructed. The demonstration costs could conceivably be in the 1-2 billion US dollar range for some concepts. Government, programmatic, and utility decision makers will ultimately need to consider the probable penetration of the various concepts in the electricity market and whether the RD&D costs are justified. Chapter 3 provides a generic list of the likely RD&D activities for the reactor and its fuel cycle, and an account system for organizing them. Some programmatic RD&D activities may benefit more than one concept, e.g., Generation IV reactor materials research. The high level figures-of-merit to be reported here are RD&D cash flows by year over the entire length of the RD&D program and their lump sum cost in constant money.

2.4.2 Capital At Risk

The specific capital investment cost of a nuclear power plant is calculated by dividing the TCIC (including base costs, owner's cost, contingency, commissioning, initial core, and interest during construction) by the design net capacity of the plant. The usual unit for this figure of merit is constant monetary unit of the reference date (e.g., US dollar of January 2001) per net kWe. Calculation of total capital investment cost is covered in Chapter 7 and represents the Total Capital At Risk.

2.4.3 Annual Non-Fuel Operation Costs (O&M costs)

This figure of merit includes the total costs of the staffing, consumables, maintenance, subcontracts, overheads, etc., that comprise the normal year by year operations of the nuclear power plant. In some years there may be capital upgrades or capital replacements that cause "spikes" in the annual cost. However, developers/estimators should average these over the number of years of operation for the purpose of cost levelization (fuel reloads are to be considered separately). A contingency should be calculated within this total to cover uncertainties in this unit cost. This cost should be reported in constant money per year. Unless otherwise specified and justified this cost will be assumed constant over the economic lifetime of the plant. Chapter 8 lists the O&M cost categories and the IAEA account system code number for each. Payments to the dismantling and decommissioning (D&D) fund are often included in O&M. If the D&D component of the LUEC is to be calculated separately, which is preferable, the annual payments to the D&D fund should be removed from the O&M total.

2.4.4 Annual Fuel Cycle Costs

This cost is the annualized cost of the reload fuel required to sustain energy production. The schedule of payments may not be the same each year because of extended fuel residence times per cycle, now higher than one year, and the staggered way in which fuel cycle materials and services are purchased. To support the EMWG approach of levelized cost calculation, the total lifetime reload costs should be divided by the number of years of the lifetime, and reported in constant money per year. Chapter 9 lists the various activities, services, and materials that comprise these costs.

2.4.5 Levelized Unit of Energy Cost and its Components

The Levelized Unit of Energy Cost (LUEC) is the high level figure of merit of most interest to utility decision makers. It is normally broken down into four main contributors to its total: a capital component (which includes up-front cost financing and amortization over the economic life); an O&M component; a fuel cycle component (fuel reloads); and a D&D component. The component costs and the total are generally expressed in constant money per unit of electricity/energy produced (e.g., US dollar/MWh). Calculation of LUEC is covered in Chapter 9.

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3. ESTIMATING CATEGORIES FOR RD&D COSTS

3.1 Rationale for Selection of Categories for Estimation

One of the figures of merit for evaluation of Generation IV systems will be the projected costs of the Research, Development, and Demonstration-Prototype (RD&D) program. These costs include the design and construction of any prototype reactor and/or fuel cycle facility. However, within the GIF Program, it is unlikely that these costs will be amortized into the LUEC, or levelized cost of other products, resulting from commercial operation of Generation IV systems (FOAK and NOAK reactors). It is likely that most RD&D costs will be financed by governments, multi-governmental organizations, and/or public/private consortia. The fact that such organizational entities are willing to support large RD&D expenditures is driven by the perceived environmental, socioeconomic, national energy security, non-proliferation, and safety advantages of the Generation IV systems. In the future, the resulting projected costs for these systems will be weighed against their likely market penetration, i.e., how well a given system fits into a national grid and infrastructure, and how it can economically compete with other energy systems.

No existing Code-of-Accounts structure, such as the EEDB or those used in the Department of Defense (DOD), fits nuclear reactor and fuel cycle RD&D costs. Based on DOE/NNSA past and present programs (such as the former New Production Reactors Program and the present Fissile Materials Disposition Program), it was possible to examine their Work Breakdown Structure and develop a generic RD&D COA. These can be divided into two major areas: reactor RD&D and fuel RD&D. It should be recognized that many of the required RD&D activities are dictated by fuel performance, safety, and regulatory requirements, such as the need to irradiate test fuel with post irradiation examination (PIE). New fuel cycles often require the design and construction of demonstration or pilot plant facilities. Table 3.1 lists the categories in a COA structure that should be found in a comprehensive generic Generation IV RD&D program.

3.2 Comprehensive COA for RD&D Activities

The expected technology development, planning, and prototype costs will be itemized and expressed in constant dollars as defined in Section 5.2 (Item 2). These include all costs necessary to bring a concept to the deployment/commercialization stage, but not including the FOAK plant costs, such as design and licensing. The first estimate of RD&D costs in the Generation IV program should have a 50% confidence level, such that the actual cost has a 50% chance of being in a particular cost range. The timing of each cost item (at 50% confidence level) should be identified. The confidence should increase with development of the technology. The cash flows for these items should be provided on an annual basis. The RD&D (including prototyping) categories of major costs for most Generation IV systems are further broken down in Table 3.1, which lists the generic categories of RD&D needed for a successful program. The prototype design and construction cost should be reported at the two-digit COA level. In addition to tabular cost data, a complete text description of the methods and assumptions used in developing the costs should be submitted with the cost data.

Table 3.1 GIF COA for RD&D support activities

Account Number	Account title
RD1	**General R&D Planning**
RD11	Planning documentation
RD12	Management and budget activities
RD13	Interfacing and permitting activities
RD2	**Reactor R&D**
RD21	Reactor Plant materials R&D
RD211	Reactor Pressure Vessel metallic materials
RD2111	Material development
RD2112	Physical testing
RD2113	Irradiation
RD2114	Post irradiation examination
RD212	Other reactor structural materials
RD2121	Reactor cooling system
RD21211	Material development including coolant
RD21212	Physical testing
RD21213	Irradiation
RD21214	Post irradiation examination
RD2122	Core internals (including reactivity controls)
RD21221	Material development
RD21222	Physical testing
RD21223	Irradiation
RD21224	Post irradiation examination
RD2123	Special non-fuel ceramic materials
RD21231	Material development
RD21232	Physical testing
RD21233	Irradiation
RD21234	Post irradiation examination
RD2124	Integral component materials
RD21241	Material development
RD21242	Physical testing
RD21243	Irradiation
RD21244	Post irradiation examination
RD213	Material selection process
RD22	Reactor analysis
RD221	Neutronic analysis/core definition
RD222	Thermal hydraulic analysis
RD223	Structural analysis
RD224	Fuel requirement definition
RD23	Reactor Balance of Plant R&D
RD231	Energy conversion system
RD232	Heat transfer equipment testing
RD233	New I&C concepts
RD234	Energy product process coupling
RD235	Other components: valves, etc.
RD236	High-temperature equipment incl. turbine components
RD24	Safety related R&D
RD241	Dynamic analysis
RD242	Early safety evaluation/PRA

Account Number				Account title
	RD25			Early design evaluation
		RD251		Economic evaluation
		RD252		Pre-conceptual design
		RD253		Viability assessment
		RD254		Analysis tools (including new computer codes)
		RD255		Parameter selection (temperature, pressure, etc.)
		RD256		Licensing and regulations criteria development
		RD257		New safety analysis criteria development
		RD258		Plant security and protection criteria development
RD3				**Fuel cycle R&D**
	RD31			Fuel requirements development
		RD311		Mechanical specifications
		RD312		Nuclear specifications
		RD313		Chemical specifications
		RD314		Fuel qualification plan
	RD32			Fuel materials development
		RD321		Nuclear materials development (metal, ceramic, etc.)
		RD322		Cladding and fuel structures development
	RD33			Fuel fab. process dev. (contact- and remote-handled)
		RD331		Basic fuel chemistry
		RD332		Bench scale development
		RD333		Process flow sheet development
		RD334		Pilot scale development
			RD3341	Pilot plant design and procedure development
			RD3342	Pilot plant construction
			RD3343	Pilot plant operations
			RD3344	Pilot plant deactivation
		RD335		Mechanical and chemical testing of fuel product
	RD34			Test fuel irradiation
		RD341		Procurement or manufacture of transport casks
		RD342		Preparation of irradiation fixtures
		RD343		Prep. of irradiation plans and safety documentation
		RD344		Transportation of test fuel
		RD345		Irradiation operations
		RD346		Scientific supervision of irradiation experiments
		RD347		Irr. test fuel removal and transport to post irr. Exam. site
		RD348		Post irradiation examination
		RD349		Scient. supervision of post exam. work and doc. of results
		RD349A		Radwaste disposal of post examination material
		RD349B		Loop test under prototypical T-H conditions
	RD35			Spent Fuel Recycling
		RD351		Basic spent fuel chemistry
		RD352		Bench scale development
		RD353		Process flow-sheet development
		RD354		Pilot scale development
			RD3541	Pilot plant design and procedure development
			RD3542	Pilot plant construction
			RD3543	Pilot plant operations
			RD3544	Pilot plant deactivation

Account Number	Account title
RD4	**Support to design, const. and operation of a demo. plant**
RD41 --------------------------------------	Reactor related activities
RD411 -------------------------	Site evaluation and selection
RD412 -------------------------	Systems analysis and integration
RD413 -------------------------	International board to direct a demonstration project
RD414 -------------------------	Prepare fuel qualification plan
RD415 -------------------------	Preparation of SAR
RD416 -------------------------	EIS environmental permitting
RD417 -------------------------	Licensing management
RD418 -------------------------	Q A activities, procedure development and training
RD419 -------------------------	Public relations activities
RD42 --------------------------------------	Fuel supply for demonstration plant
RD421 -------------------------	Nuclear materials
RD422 -------------------------	Other fuel parts
RD423 -------------------------	Pilot plant staffing
RD424 -------------------------	Pilot plant replaceable
RD425 -------------------------	Pilot plant waste handling
RD426 -------------------------	Fuel quality assurance and inspection
RD427 -------------------------	Fuel packaging
RD5	**Design, const., op. & decom. of a demo./prototype plant**

Note: It is appropriate to use the GIF COA for capital cost and fuel costs for a full cost accounting for a demonstration plant.

4. GENERAL GROUND RULES AND ASSUMPTIONS

4.1 Introduction

This chapter describes the general ground rules and assumptions to be followed in developing the base construction cost for the advanced concepts. It provides a framework for development of cost estimates by methods appropriate to the level of design definition available for the concept. In the conceptual and preliminary design phases, the top-down estimating approach will be appropriate for majority of the scope (Chapter 5) and as design gets more and more detailed, the bottom-up estimating approach will be more appropriate for majority of the scope. (Chapter 6).

Nearly all these ground rules are based on design and construction practices in the United States for past and existing nuclear projects. It is expected that the same principles are appropriate for other regions though the level of available cost detail may not always be readily available. The EMWG will incorporate specific input from other regions and conversion of measurement units to international standards, as such information can be found.

Appendix G provides data requirements to support the estimating process as well as examples of US Nuclear plant construction experience from the 1970's. Examples of top-down estimating techniques are provided in Chapter 6 and Appendix H.

4.2 Project Execution

The assumptions on the organizational structure to be used in developing the cost estimate are described below. These are based on traditional US business practices. Generation IV nuclear system projects may have a non-traditional structure. The project management structure must minimize risk and complete the plant on time and on budget.

1. Overall project management for an energy system will be provided by an integrated utility, a generating company (GENCO), or another entity engaged in the direct production of commercial energy. For regional fuel cycle facilities, a chemical or nuclear service company already engaged in this line of business is assumed to provide overall project management. For module fabrication, a heavy machine fabricator or shipbuilder is assumed to handle management responsibility. If fuel cycle or end-use facilities are on the reactor site, their owners will bear their part of project management responsibilities.
2. A single reactor manufacturer (RM) and a single A/E contractor (i.e., single mark-ups for their services) will be employed to design NSSS and other nuclear plant equipment, to design plant buildings and structures, to prepare all technical documentation and reports, to provide all procurement services and to support construction activities.
3. A single construction manager, who may also be the A/E, will be responsible for providing PM/CM services to manage all construction activities.
4. These assumptions do not exclude a single vendor/generating entity that would supply and construct commercial facilities. The estimator must clearly state all assumptions regarding organizational structure.
5. Construction of the project will be estimated based on work being performed on a regular working week. Alternative schedules such as double shift or rolling 4-10s, may be addressed in addendum.

4.3 Commercialization Plan

1. This is the first phase of project development through the R&D phase. Each technology will be evaluated for compliance with the stated goals of this phase before approval to proceed to phase II – conceptual design.
2. Successful designs may proceed to phase III – detailed design, including any prototype or demonstration testing and concluding with plant certification of a standard design.
3. Commercial plant commitments for multiple plants will be obtained before the first commercial plant (FOAK) construction on an approved site.
4. All project services, procurement and construction award will be based on competitive bids for a series of identical plants.
5. Dedicated factory facilities for fabrication of plant equipment or factory modules will be constructed or adapted to support construction of the FOAK plant.
6. The development of fuel fabrication facilities may proceed concurrent with the conceptual design and detail design phases for the power plant dependant on the source of first reactor fuel.
7. Fuel reprocessing facilities may proceed concurrent with the power plant conceptual design and detail design phases, depending on scheduled requirements for reprocessing services.
8. Subsequent plants up to NOAK plant will be constructed without any significant changes in the certified design.
9. NOAK plant is defined as the next plant after 8 GWe of plant capacity has been constructed. This rating, together with consideration of plant capacity, sequence and timing of unit construction provide a basis for calculation of learning affect on cost of plants between the FOAK and NOAK plants.
10. For purposes of sizing the fuel fabrication and reprocessing facilities, a nominal fleet size of 32 GWe is to be assumed for each reactor type.
11. Detail design, certification and other non-recurring costs will be separately identified and assumed to be amortized over the plants prior to NOAK plant.

4.4 Estimate Components

Describe estimate components and identify how they are handled in the estimating process and COA [includes specifying unit, common or recurring cost item, nuclear island and balance of plant, FOAK or NOAK cost estimate, direct and indirect costs, schedule of expenses, contingency, phases of project development, power of the plant considered, costs associated with non-electrical production if applicable, costs of dedicated factories, for fuel fabrication or reprocessing for example, if applicable, capitalized and annual costs, financing, decommissioning costs].

4.5 Project COA

1. The GIF COA (originally derived from the IAEA and EEDB COA) will be the structure used for cost estimates. Used by ORNL, the EEDB COA was an evolutionary expansion and modification of the NUS 531 COA. The EEDB also served as the basis for the capital part of the IAEA account system described in (IAEA, 2000). Sample EEDB COA for the advanced liquid metal reactor (ALMR), the modular high-temperature gas-cooled reactor (MHTGR), and a light water reactor are given in Appendices A, B, and C of (Delene, 1993). See Appendix F for full GIF COA structure and dictionary.
2. The use of a consistent COA structure facilitates top-down estimating techniques when reference plant data and estimate details are summarized to the desired level for facility, system, or major

equipment component. These estimate summaries are then adjusted by cost factors developed for the required plant relative to the reference plant parameter. All the available reference plant estimate details can then be incorporated into the subject plant estimate inclusive of commodity quantities, hours, equipment, and material costs.

3. Consistent COA can support estimating techniques that relate system bulk commodity costs to cost of process equipment which is typically defined early in the design process. Reference plant detail estimates summarized by COA can provide bulk commodity ratios to equipment cost that can subsequently provide the basis for current estimate with current pricing of process equipment costs.
4. Within the structure of GIF COA, each technology is to develop a detail COA that uniquely defines the specific plant features to ensure full and exclusive scope for the project.
5. The COA will be the basis for subsequent project development of equipment numbering, plant area designations, drawing register and other consistent identity applications throughout the plant life, including operations.

4.6 Project Scope Definition

1. Whenever possible, the cost estimates will reflect the plant requirements and design as detailed in the Design Requirements, System Design Descriptions (SDDs), and other formal design documentation for the given concept. Individual system boundaries will be defined in the SDDs. It is recognized that none of the Generation IV concept designs have evolved to the point that these documents are available.
2. It is expected that each reactor concept project scope definition will consist of facilities and systems that are developed specifically for the reactor concept, some systems that can be adapted from reference plant data and others that can be extracted entirely from reference plant information. For example, the reactor system may require unique design, while the reactor cooling system could be an adaptation from reference plant design with appropriate cost factors and some BOP systems may be completely defined by reference plant data. Different estimating techniques may be employed as appropriate for each type of project scope definition.
3. As an aid in establishing system-to-system boundaries for COA definition and costing purposes, the following general guidelines are given. These apply to reactor and fuel cycle facility concepts for which the design is at least at the conceptual level.
4. The cost for all electrical power terminations, including connectors, should be borne by the electrical power system. For the trace heating system, the interface with the electrical power system is the individual heater controllers. For building service power and lighting systems, the interface with the electrical power system is the individual power lighting panel.
5. The expense for terminating instrumentation and control cabling and wiring (with the exception of control system fiber optic cabling) should also be included in the electrical power system. This includes terminations with individual sensors as well as providing electrical interconnections between panels, cabinets, consoles, data processing units, controllers, etc. The expense for terminating the control system fiber optics is included with the control system.
6. Costs for routing, laying or pulling wire and cable in ducts, conduits, and trays will be included in the electrical power system.
7. The costs for attachments to structures (e.g., anchor bolts and auxiliary steel) should be borne by the equipment item requiring the support. Embedments (such as sleeves and attachment plates) are included in the cost of structures.
8. The cost estimate for a system, equipment, facility, or structure will include those costs associated with fabricating, installing, and/or constructing the particular item described in the SDDs or Building and Structures Design Descriptions (BSDDs).

9. For costing purposes, the boundaries of a system, facility, or structure are as defined in the SDDs or BSDDs and in the piping and instrumentation diagrams (P&IDs).
10. The industrial non nuclear-safety portion of each plant is designed and erected to the same standards as a conventional fossil-fuel power plant. Only the nuclear-safety-grade structures and equipment require the more elaborate procedures, documentation, and Q/A-Q/C overview. Any on-site fuel manufacturing, handling, and reprocessing, or other fuel cycle facilities, will be assumed to be nuclear-safety-grade.
11. Project scope definition for the indirect cost is typically defined by other than design documents. Field indirect costs are influenced by the project execution plan, construction schedule and major contracting decisions. The indirect cost is also very dependant on the direct costs of construction. Direct hours are of major consideration for both the construction schedule and the magnitude of indirect support required. To this end, it is vital that direct hours are quantified throughout the estimating process and are available by category of work or craft.
12. Non-manual services for field and home office are typically defined by manpower and durations for major tasks involved with each COA scope. The level of detail for the tasks involved will progress from initial summary levels in conceptual estimates to detail tasks with sequence logic in finalized estimates.
13. Engineering and Home Office Services includes the A/E costs for design, engineering, procurement, cost engineering, Q/A−Q/C, reproduction services, etc. (Account 35 and 37).
14. Any module fabricator (factory owner) costs for engineering, Q/A, etc., should be separately shown. Reactor design costs by the manufacturer should also be separately shown.

4.7 Inclusions/Exclusions/Qualifications

1. It is assumed that all engineering and cost information, including specifications, drawings, and virtual construction and sequence (CADD output) and that all equipment, material, and labor resources are available as required.
2. It is assumed that the baseline construction requires no premium time (overtime) work to recover from schedule delays. Costs for possible schedule recovery overtime will be reflected in the contingency cost (see Section 6.3). The use of premium time for normal baseline construction over and above a standard working week should be identified.
3. It is assumed that funding is available as required to support uninterrupted design, testing, construction, installation, checkout, and plant startup.
4. Cost items to be excluded from the base construction cost estimate include items beyond the plant bus bar, such as the switchyard and transmission lines. See plant site definition in Appendix D for other site related assumptions.

4.8 Project Estimate

Assumptions and general ground rules for project estimate are provided by subject in the following subsections, starting with overall project estimate below.

1. The base construction cost estimates will be developed so that they are the most likely cost for a particular cost entry without any IDC, escalation, or contingency as defined in Section 1.4. All values defined as costs to the buyer include supplier profit margins.
2. Estimate details are to be summarized to level 2 of COA and provide input to other cost models for calculating LUEC.
3. installation costs should be based on quantities, installation rates (see Tables 4.7 through 4.9) and labor rates (see Tables 4.1 through 4.3) The basic cost algorithm for a particular account code is:

The estimate cost components should be consistent with the pricing basis defined by these guidelines. The costs should be in constant dollars for January 1, 2001 pricing levels as depicted in tables G.1.4 through G.1.6, productivity of the inherent direct labor should be as depicted in tables G.1.7 through G.1.9 and the cost of labor as depicted in tables G.1.1 through G.1.3.

4. All construction will be estimated as direct hire, including specialty contractors. All field labor will be quantified and included as labor cost. Process equipment will be separated from all other equipment and material costs.
5. Estimate reporting requirements are discussed in Section 4.12.

4.8.1 Estimate Pricing Date and Currency

1. Cost estimates will be reported in constant dollars of January 1, 2001.
2. Bulk commodity unit hour installation rates are given in Tables 4.7 through 4.9 for nuclear and non-nuclear construction practices. Bulk commodity definitions are given in Table 4.10. The craft labor rates shown in Table 4.1 were obtained from escalation of Mean's Construction Data (Reed Business, 1992), for year 2001 for a medium labor cost U.S. site. Tables 4.2 and 4.3 show the corresponding craft labor rates for Europe and Asia regions. The labor installation rates were developed by applying a productivity factor to estimating standard rates. Nuclear productivity factors were developed from a set of early nuclear projects, which did not experience post-TMI (Three Mile Island, March 1979) back-fitting. Non-nuclear installation rates were developed from current fossil power project experience. The commodity installation rates (Table 4.7) are not a complete set of such information needed to cost a plant design, but are provided as an example of the productivity level for the construction scope.

   The composite costs of bulk commodities shown in Table 4.4 were escalated from historical data by Whitman *et al.*, 1992 index for the North-Central Region of the U.S. The bulk commodity unit costs (Tables 4.4 through 4.6) are intended to be a measure of bulk commodity pricing levels for the different regions.

   Any exception to the labor rates, commodity prices and installation labor hours shown on Tables 4.1 through 4.10 should be justified.
3. The estimator will use cost information relevant to the reference date (January 1, 2001, for current studies) where possible. If such information is not available, costs in terms of another reference year may be adjusted, where applicable, using appropriate cost indices. Examples of such adjustment factors using both the Gross Domestic Product implicit price deflator and the Handy-Whitman cost index for Nuclear Production Plant Electric Utility construction costs (North Central region) are given in Table 4.11.

4.8.2 Direct Equipment and Material Pricing

1. Assume that the cost of using any government-owned or operated facility is estimated at full cost recovery, including all direct costs, related indirect costs, and any other related general and administrative costs.
2. All construction and installation costs may reflect a separated construction concept whereby nuclear-safety grade and Seismic Category 1 construction are separated from conventional industrial (non nuclear safety) construction. All costs of equipment, materials, storage, quality assurance (Q/A), quality control (Q/C), and labor productivity for the non nuclear-safety areas will reflect conventional nuclear industrial practice. The portions or fractions of the plant constructed under each construction grade shall be documented.
3. If a plant uses a new, dedicated factory for producing construction modules for the NSSS and/or balance of plant (BOP), the proper amortization of the factory cost over its production life must be

included in the FOAK and subsequent plant costs. If an existing factory/plant is used, or if a separate business model has been adopted for dealing with those costs, the basis for site-delivered cost assumptions should be reported. These should include factory construction cash flow, capitalization, operations cost, and amortization assumptions (e.g., number of units assumed for factory capital cost recovery).

4. Majority of the Equipment for Nuclear Power Plant systems are expected to be world-wide pricing levels and not differ significantly by region. Equipment costs are to be inclusive of vendor design, fabrication, testing and certification, packing for in-country shipment and normal 12 months warranty. The costs are delivered to site, excluding freight forwarding, ocean shipment and customs clearances. The costs include allowances for installation materials and any construction spares; any pre-service maintenance requirements are also included. Plant start-up, commissioning and operational spares for 12 months are to be included with indirect accounts.
5. Majority of the non process equipment and materials for nuclear power plant facilities or systems are expected to be world-wide pricing levels and not differ significantly by region. Some bulk commodities such as concrete, lumber, small pipe, miscellaneous steel, embedded metals and similar locally procured items may differ by region and the pricing levels depicted by the sample unit costs in Table 4.4 need to be provided with the estimate submission.

4.8.4 Direct Labor Productivity

1. All plant construction will be accomplished by the labor force with exception of specialty tasks subcontracted by the A/E. Costs for all tasks, including subcontracted tasks, must be reported as equipment cost, material cost, labor hours and labor cost per hour. Specialty subcontractor overheads are typically included with material costs.
2. The unit hour rates depicted in table 4.7 are representative of the productivity determined for US advanced nuclear plant construction. A productivity factor was determined for a mid USA site based on actual construction experience (pre TMI event) adjusted for benefits of a standard nuclear power plant with complete design that has been pre-certified. The rates were calculated by applying the productivity factor to a set of standard unit hour rates for all construction activities.
3. The rates are representative of a standard working week for a commercial plant, better than a test or demonstration facility. Additional improvements may be applicable for NOAK plant, see section 4.10 and appendix E.

4.8.5 Labor Cost/Hour

1. Labor rates for craft labor employed to assemble equipment at any on-site fabrication shop will be the same as construction crew rates. Off-site craft rates at a module factory are likely to be lower and the work more productive, steady and safer than for on-site fabrication, but will incur factory overheads.
2. Composite cost per hour for manual labor includes a craft mix for the category of work; craft crew consisting of journeyman, foreman and apprentices; craft wages; premium cost (if any); travel or living allowances, geographic factors, merit factors, public holidays, sick leave; vacation pay; pension funds; medical insurance; unemployment insurance; and all labor related costs paid by employer such as taxes and insurance.
3. Construction camp related costs for housing; meals and transport are excluded from the composite cost per hour, if required, should be included with the indirect accounts.
4. Other labor related costs such as tools, supplies and consumables are excluded from the composite cost per hour and are to be included with the indirect accounts.
5. Composite labor costs (base rate plus fringe benefits) to be used for the U.S. site in 2001 dollars are given in Table 4.1.

6. Composite costs per hour for non-manual personnel include payroll, payroll additives, bonus, incentive pay, taxes, insurance, superannuation or retirement funds, and other payroll related costs. Excluding office supplies, office equipment, office space, travel, relocation, training or other ancillary costs.

4.8.6 Field Indirect Costs

1. Indirect cost accounts consist of all costs that are not directly identifiable with specific permanent plant, such as 31 - field indirect, 32 - construction supervision, 35 & 37 design services, and 36 & 38 PM/CM services.
2. Material handling for major equipment is to be included with direct accounts. Maintenance of permanent plant equipment prior to plant start-up is to be included with direct accounts. Crane operators and truck drivers for support of direct account activities are to be included with direct accounts.
3. Only multi purpose, multi craft scaffolding and staging is to be included with indirect accounts 31. Single craft scaffold and mobile platforms are with direct accounts.
4. Individual craft clean-up is with direct accounts, general site clean-up and trash handling is with indirect accounts 31.
5. Installation spares are with direct accounts, spare part requirements during testing is with indirect accounts 33 or 34. Operating spares are with supplementary cost account 52.
6. Construction testing of installed systems is with direct accounts. System pre-operational testing and start-up activities are with indirect account 33. Plant demonstration test run is with account 34, Operator recruitment, training and other associated costs are with owner account 40.

4.9 Region and Site Definition

The following regions have been considered in the present version of the Guidelines for development of plant estimate: Americas, Asia and Europe.

1. Site/Seismic conditions for each region are considered in Appendix D. Most current North American, Asian or European reference site data is proprietary and cannot be used in this report. It will be necessary to eventually collect and/or develop such data.
2. Site land (Account 11) should be based on the estimated site area, including any buffer zones (200 hectares minimum) and a cost of $37 000/hectare in the United States. It is assumed that the total land cost is incurred at the same time as the decision is made to build a plant.

4.10 FOAK Plant

The following assumptions apply to costing the FOAK plant.

1. The costs for this plant should not include any RD&D (including prototype) costs. They can include site-delivered equipment costs from a dedicated factory and design certification costs. The total FOAK plant cost has two basic parts as shown in Fig 1.1 under "deployment": the standard plant cost, i.e., the types of costs that will be repeated in subsequent costs (site-related design and construction); and the true FOAK costs, such as first-of-kind design and design certification costs. If there are exceptions to this, these must be clearly identified. Regarding fuel cycle FOAK costs, the fuel cost for all units, FOAK through NOAK, will include its fair share of the life cycle costs for a new fuel cycle facility constructed either on-site or off-site. Fuel facility construction costs are part of these fuel-related life cycle costs.

2. Each system development team (Proponent) will perform the estimates for the standard FOAK plant based on current construction experience for similar facilities. Learning experience can be included for NOAK plant based on learning factors to be developed by each team. Guideline factors for each doubling of construction experience are 0.94 for equipment costs, 0.90 for construction labor and a 10% reduction in material costs for multi plant orders.
3. The cost estimate will include the cost for all site-specific licensing or pre-licensed sites. A generic plant design approval (certification) is part of the FOAK non-recurring deployment costs.
4. Standard plant costs include all engineering, equipment, construction, testing, tooling, project management costs, and any other costs that are repetitive (recurring) in nature and would be incurred in building an identical plant. A sample listing of mostly site-related repetitive engineering and management tasks is presented in Appendix C.
5. Appendix E deals with learning and the relationship between the capital costs of the POAK, FOAK, and NOAK plants. Because system development teams are estimating FOAK costs, Appendix E discusses how POAK and NOAK costs can be reasonably estimated from FOAK costs.

4.11 NOAK Plant

The following assumptions apply to costing the NOAK plant.

- Design is identical or nearly identical to the first commercial plant (any engineering or license changes from the FOAK must be amortized)
- The plant site is enveloped by the reference site conditions.
- No product improvements are incorporated; that is, the first commercial plant design is frozen.
- Equipment manufacture and plant construction are performed by the same contractors as for the first set of plants.
- All project services, procurement and construction award will be based on competitive bids for a series of identical plants.
- There are no changes in USNRC (or other national) regulations or major codes and standards subsequent to the first plant.
- The cost estimate will include the cost for all site-specific licensing or pre-licensed sites. A generic plant design approval, e.g., design certification in the United States is assumed.
- Plant costs include all engineering, equipment, construction, testing, tooling, project management costs, and any other costs that are repetitive in nature and would be incurred in building an identical plant (see Appendix C).

Nonrecurring engineering and home office services costs of the RM or EQM are assumed to be zero for the NOAK plant. Any applicable recurring RM or EQM engineering costs should be identified.

4.12 Estimate Reporting Format

1. Capital costs should be separated into two categories related to whether the equipment/construction is nuclear-safety-grade or industrial non-nuclear-safety-grade. The plant design contractor (RM, EQM and A/E) will determine the boundaries of the nuclear-safety-grade and industrial non-nuclear-safety grade areas. Costs within each category will be reported in GIF COA format as illustrated in Appendices A, B, and C of (Delene, 1993) and in the modified IAEA format (see Appendix F).
2. Although included and reported in the overall plant estimate, costs of common plant facilities will, in addition, be identified at the two-digit account level and listed separately in GIF COA format.

3. In cases where equipment items or piping are combined with structures to produce a factory-assembled equipment module, a work sheet documenting each module should be prepared. The work sheet will identify by three-digit GIF COA the applicable items and costs that comprise the module. For each three-digit account, the work sheet will provide the equipment and material costs, shop, and field labor hours and costs, factory overhead and profit, freight, and total module cost. In addition, the text must describe the approach used to estimate each of the cost items. For the total plant cost estimate three-digit level costs for items that are part of a factory module must remain in the GIF COA that represents that particular item. So, costs for structural portions of a module should be reported in Account 21 and equipment/piping costs should be reported in the relevant system account (Accounts 22-26). The total factory cost, including shop labor and materials, should be recorded as factory equipment costs in the GIF COA cost estimate format. Field labor to install a module should be recorded as site labor in the GIF COA estimate format. Labor costs to produce and/or install a module may be prorated among the related three-digit GIF COA, if necessary. The basis for cost-related assumptions regarding the module factory must be documented. Such assumptions include factory location, factory labor rates, and amortization of factory capital costs over the fleet size of module production, labor unit productivity, factory overhead, and module shipping cost assumptions. The wage rates for factory craft workers should be based on the local craft labor data for the factory site. Any adjustments to the labor rates to reflect the factory environment, including overheads and general and administrative (G&A) costs must be fully supported in the future cost estimate reports. For large equipment items and modules, the site delivered transportation costs are to be identified as a line item.
4. For large factory equipment items, such as the reactor vessel and internals, steam generators, heat exchangers, etc., supporting cost data by component must be available for review. The supporting data will include factory material cost, material weights, factory labor hours, recurring cost, and total cost for each equipment item.
5. All construction will be estimated as direct hire, including specialty contractors. All field labor will be quantified and included as labor cost. Process equipment will be separated from all other equipment and material costs.

5. GUIDANCE FOR COST ESTIMATES PREPARED BY THE TOP-DOWN APPROACH

For several years, during the early phase of the Generation IV RD&D program, designs will be "pre-conceptual" for the less mature concepts and "preliminary" for the more mature concepts. In this situation, appropriate data for some of the plant systems may be lacking to develop a bottom-up cost estimate. Therefore, a more global approach, the top-down approach, is needed to help the designers and decision makers in comparing design options. Top-down approaches use simpler models than the ORNL bottom-up approach adopted for the 1993 evaluation of the MHTGR and LMR. The approaches described below keep the GIF COA structure at a two-digit level, with aggregation of many sub-accounts.

Some of the systems comprising Generation IV plants will have similarities in BOP and reactor systems, facilities and buildings that can be related to previously-studied advanced nuclear plant technologies. Some of the systems may have similarities to non-nuclear technologies and if suitable cost data is available, it could be utilized for estimating subject plant equipment or system. The systems that are unique to a new technology may need to be sufficiently defined and their major parameters quantified to establish relationships to previously studied plants. Other, more common systems and facilities might be directly estimated with global adjustments for plant ratings and current pricing.

This chapter describes some of the top-down estimating techniques that could be utilized; other techniques could be utilized if the resulting estimates have been validated to current pricing data. These guidelines do not provide a comprehensive handbook on cost estimating of future nuclear systems which would include more exhaustive data, detailed method descriptions and extensive examples of complete energy plant estimates. Such data acquisition and complete examples of applications is currently outside the EMWG charter.

5.1 Cost Modeling Needs of Innovative System Designers

A reactor system designer starts by conceptualizing a coherent image of a new system (reactor, fuel cycle, optimized electricity generation or process heat co-production, etc.). Within GIF, this image aims at meeting the major goals of Generation IV systems in the fields of economics, safety, use of resources, reduction of wastes, and resistance to proliferation. The designer develops a reference design for the primary nuclear energy plant components, the safety system, and the containment with the help of computer models, such as fuel performance codes and thermal hydraulic models.

After developing a "back-of-an-envelope" conceptualization, the designer must verify and optimize a concept before launching detailed engineering studies. In the RD&D program the designer needs economic models to develop and compare design options around the reference concept. The top-down modeling approach has been developed in Argentina (Grinblat *et al*., 2002), Canada (Duffey, 2003) and France (Nisan *et al.,* 2003). These types of studies have also been proposed for US reactor concepts (Yoder *et al.,* 2002) and used by DOE for other advanced energy systems (Williams, 1984, and Delene *et al.,* 1988). It is a relevant economic modeling technique for this phase of the GIF Program.

5.2 Top-down Modeling Principles

The basic principle in developing a top-down model is that for most advanced development projects, especially in their preliminary phases, it may be sufficient to make an approximate cost estimation by the simplest and fastest methods available. The results obtained are then further refined in progressive stages of the project when choices of options and technologies are more developed. The most important requirement is that consistent estimating techniques be used for the systems considered so that economic comparisons can be made between competing design alternatives within a given concept. To this end all costs should be captured in the GIF code of accounts to the appropriate level of detail. Components of an estimate may be developed at a high level of detail and summarized to a consistent code of account level for inclusion in the overall estimate.

Another top-down estimating technique uses costs of process equipment that are better defined and then applies bulk factors for other commodities that typically are not detailed when the initial estimate is undertaken. This technique requires bulk factors to be derived from similar nuclear power or non-nuclear project cost data. This cost estimating approach has been used in the chemical and petrochemical industries where continued development over several decades has produced simple, but powerful, methods for cost evaluations.

i. *Top-down Modeling by the designers*

The designer of a new concept has already (§ 5.1) a coherent conceptual image of his system and the possible variations, but a blank page on construction cost. How should he proceed?
First, he will decompose its concept into several “cost modules.” A cost module represents a group of cost elements (or items) having similar characteristics and relationships. Each of these cost elements can represent a task in the overall cost module, e.g., site acquisition and development, system or major process equipment, such as a pressure vessel, etc. As a minimum, the cost modules should correspond to the level 2 Code of Accounts structure.
Then, he will find the most suitable methods to cost estimate the different elements of his cost modules by comparing them to other elements whose costs are better known.
There are several methods which, for our purpose, can be differentiated in:

	Direct Analogy	Modelization
Principle	Integrate the element in an homogeneous family	Determine differences between the element and a reference, and construct a model able to cover the variations of the element
Advantages	Fast, low cost Easily traceable Credible for an homogeneous family	Fast Flexible Dialogue tool
Disadvantages	Data number Lack of fineness	Black box Training

Direct analogy necessitates a sufficient number of cost data. This is for example the case of gas turbines whose prices are published worldwide. This is more frequently the case for small equipments, pipes, pumps, HVAC devices…
Modeling is usually used when direct analogy is not possible.
A great number of construction cost estimating has been developed. They are described in handbooks quoted in references of this chapter (Chauvel and Peters). Let us retain for the type of cost estimating we need that the exponential methods are the most useful in our cases. (chapter 3.2.1 of Chauvel), but factorial methods (chapter 3.2.1 of Chauvel) are also interesting, notably for the ratios of equipment cost to functional unit installed.

Exponential cost models are in the form of a simple generic equation such as:

$$C_i = A_i + (B_i \times P_i^{\,n}),$$

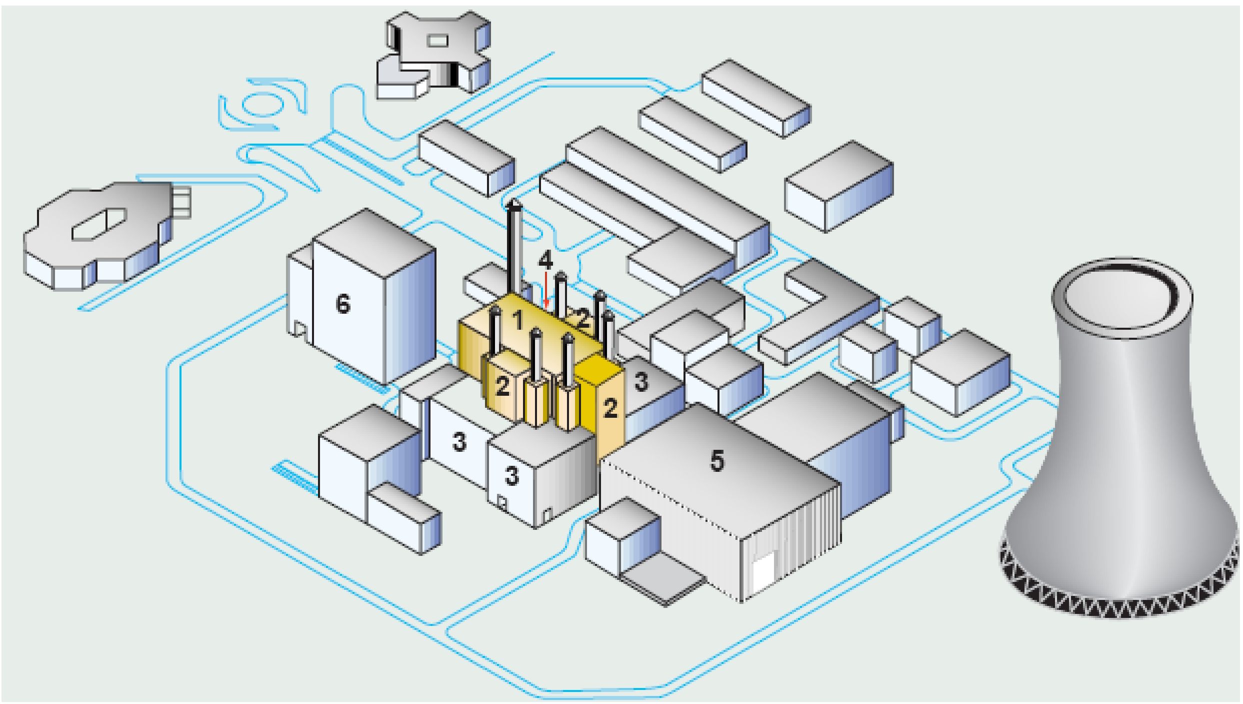
where:
Ci is the cost of the subject plant element;
A_i is a fixed component of the reference plant cost;

B_i is a variable component of the reference plant cost;
P_i is a ratio of subject plant to reference plant component parameter value;
^{n} is an exponent that reflects the size benefit of rating for the component; and
Pi^n is equivalent to a cost factor for ratio of parameters between subject plant and reference plant data.

The chapters of Peters "Cost components in capital investment" and "Methods for estimating capital investment" (pages 239 to 258), give equally good examples of such methods.
Both handbooks give models for components and equipments such as pipes and pressurized vessels (pages 627 to 634 of Peters).

5.2.2 Application to nuclear reactors

A nuclear reactor is usually represented by an image such as:



Inside each of these buildings, there are civil works, equipments, electrical and mechanical systems…
These elements are gathered in level 2 COA cost modules.

Specific cost models may be developed for major process equipment such as reactor vessel, steam generators or large heat exchangers that relate costs to ratings, materials and other details developed specifically for the subject plant. They usually require the project team to develop additional data to support cost development, especially for unique features that cannot be ascertained from reference plant data. Specific models may include graphs and/or complex equations.

As an example, the cost evaluation model for a PWR pressure vessel was developed from available models for the stainless steel-lined, high-pressure vessels used in the nuclear industry. It resulted in an equation similar to:

$$\text{Reactor Vessel Cost} = A[(B \cdot dv + E) \cdot (hv/3)^{0.5} \cdot (dv/0.6)^{0.1} \cdot F(kpv + G)],$$

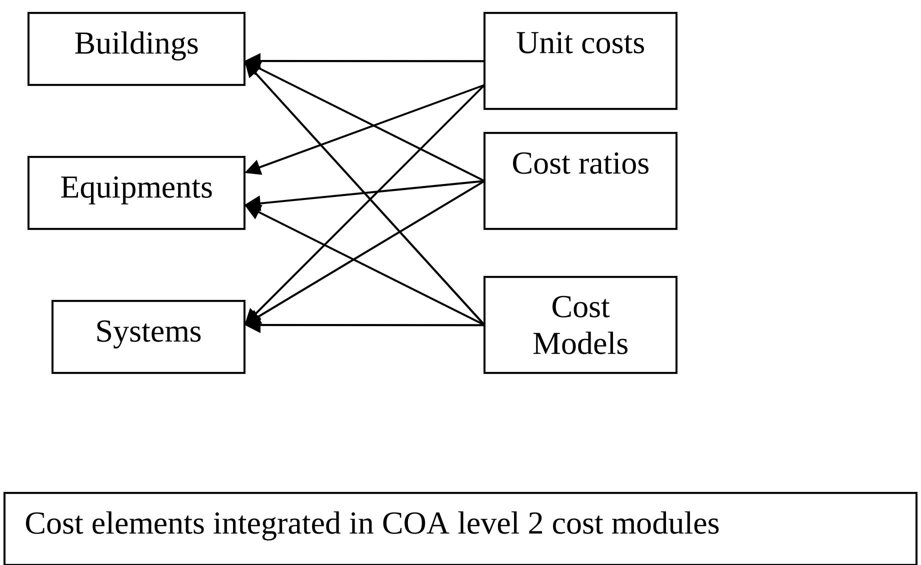
where:
dv is vessel diameter;
hv is the vessel height; and

kpv is a coefficient that represents the pressure vessel.

The adjustment coefficients are obtained by applying well known statistical techniques (e.g., ordinary least squares) for a large number of values of *P* (e.g., a range of MWe values). The models are more finely tuned by using reference or published data on existing installations and by taking into account field materials, field labor, and other industrial factors. Finally, a validation of the model is undertaken by comparison of the model output to current vendor pricing data, historical data, or detailed reference plant estimates.

b. Top-down estimating process

The top-down estimating process is illustrated by the following scheme:



For buildings, formulae exist to estimate the construction cost starting from base cost of m^3 of concrete or base cost of m^3 of building volume.

For equipments, ratios and specific models are used.

For systems, unit costs, cost ratios and models are used, depending on the level of detail design.

Examples of top-down cost estimating process are given in appendix H.

5.3 Use of Top-down Modeling for Generation IV Systems

5.3.1 Reference Conceptual Design

To develop a cost model of a nuclear energy system, the following minimum design information is needed:

- a description of the process and its reference operating conditions (including energy and material balances);
- a schematic figure of the major nuclear components (reactor vessel, steam generator, heat exchangers, etc.) and coolant circuits (active and passive safety circuits) with conceptual size and layout arrangements (geometry);
- the type and volume of containment/confinement; and
- a description with major dimensions of the facilities outside the nuclear island.

This information is used as follows:

- Equipment cost can be derived from known cost of similar equipment with cost factors derived by the ratios of known parameters, such as rating, capacity or weight. Cost exponent factors are typically used in establishing the cost factor from the ratio of parameter data, as discussed in section 5.3.3.
- For system cost data, specific cost models may be applied, but generally, a rough sizing of the system and physical parameters established for weight, volume, materials, complexity, or other environmental factors can be compared with reference plant data and identified differences estimated or a cost factor applied, based on expert judgment.
- Buildings and facility structures can be estimated by application of unit cost rates to the quantity of commodities, when dimensions and type of structure are known.
- Bulk commodities, such as pipe and cable, can be estimated with global models from cost data obtained from reference plant information. Differences can be estimated or a cost factor applied, based on expert judgment.

5.3.2 Reference plant data

A reference conceptual design cost model is an assembly of several models and data allowing cost estimations that are representative of the concept studied. The reference plant data may consist of several plants with systems or component that are similar to subject plant. The reference plant cost data will be the basis (tool box) to estimate costs for the subject plant design. Reference plant data will consist of technical and physical scope information defined by P&ID's, System Design Descriptions and data sets, process flow diagrams and facility arrangement drawings. The corresponding cost estimate will be available with details to commodity level, and will typically include COA, description, quantity, equipment cost, material cost, hours, labor cost, and total cost by line entry. The estimate definition will include a description of the project execution plan; basis for scope development; date of pricing; direct productivity data; craft wage rate information and basis for other project costs. Typically, the discussion of project contingency cost determination provides a good understanding of the confidence levels for various components of the cost.

1. Before any part of the reference plant cost data is utilized, several adjustment factors need to be calculated for application on a global basis for all reference plant direct cost detail records.

2. The pricing basis of the reference plant estimate requires a global cost factor for all costs except labor. (Labor cost will be adjusted with factors for productivity and local wage rates). Process equipment and materials can be adjusted globally, by establishing cost factors based on various cost indexes between the reference plant date of pricing and the subject plant pricing date and applied at an appropriate level of detail.
3. Currency conversions, if required, should be performed by establishing the appropriate cost factors that will apply to process equipment and material costs only. Labor will be extended based on subject project productivity and composite cost per hour.
4. Analysis of the sample unit hour rates between the reference plant estimate and the subject plant requirements, can establish a comparative productivity level and a cost factor to adjust all the craft hours at the direct cost level.
5. Labor cost is best adjusted by applying composite labor cost per hour that has been developed specifically for the subject plant and reference pricing date.
6. Other project costs, including field indirect costs are to be separately developed for the subject plant after all the direct cost components are summarized and a construction schedule established. Comparisons to the reference plant ratios can provide a validation check for the subject plant estimate.
7. The subject plant COA definition is utilized to ensure that all the required scope is identified for an estimating basis by identification of a reference plant for top-down estimating technique or some other estimating technique such as equipment bulk factors or bottom-up commodity detail estimate. Different reference plants can be utilized that are most appropriate for the scope of the subject plant. The entire project scope is identified to an estimating technique that is most appropriate to each segment together with the source reference plant data.
8. It is recommended that all the global adjustments are incorporated in an update of the reference plant cost estimate details together with any re-alignment for GIF COA structure, such that a completely normalized and relevant cost data base is established for use by the subject plant design team.
9. The team selects an appropriate section of the reference plant project scope that is most similar to the facility, system or COA for the subject plant and extracts the estimate details for the corresponding scope.
10. An appropriate major parameter is established for the selected scope and a cost factor calculated for the ratio of the parameters between the subject plant and reference plant ratings.
11. An estimating cost model is established consisting of: links to the reference plant detail estimate; all the cost factors required to normalize the data for the subject plant; system or COA parameter cost factor development for the selected COA; and resultant COA detail for the subject plant. The model will include ability to perform checks and validation of the resultant subject plant direct cost estimate and provide refinement COA adjustment factors for the details.
12. Extracted summary information will provide input data with selected quantities and labor requirements to support development of construction schedule. Future development may facilitate schedule development with iterative process linked to the estimate details and construction plan inputs such as work week, sustained installation rates and manpower densities.
13. Validated cost details will be summarized to second level COA and provide input to other cost models for calculation of LUEC.

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5.4 *Design Options Studies*

Once the first baseline design for a new concept has been modeled using cost-scaling equations, the designer can use the integrated design/cost model with an optimization package to further develop the concept. This should be done before launching into more detailed studies using a fixed baseline design.

The potential of this top-down approach for assessing the economics of co-generation of potable desalinated water and/or hydrogen by products with electricity will be studied within the framework of the EMWG integrated modeling system in 2006. In the course of further engineering studies, both bottom-up and top-down approaches will be used to better estimate the costs of the different parts of the Generation IV systems, including innovative fuel cycles.

5.5 *Generic Studies*

Generic studies to analyze size (modularity) and series effects (e.g., cost beneficial effects of learning in manufacturing and construction) can be performed with the help of top-down modeling (see Marcetteau *et al.*, 2001). This type of work will be extended in future investigation by EMWG of monolithic versus modular construction costs. The effect of modularity on the marketing and reliability of electricity will also be considered.

5.6 *Top-down Approach for Indirect Capital and Non-Capital Life Cycle Costs*

Most of the discussion above dealt with the top-down scaling of equipment and structures for the new concept. These costs would be rolled-up to the two-digit level as Accounts 21-29. Indirect costs are mostly project support labor costs. These are not usually estimated early in the RD&D program. There are, however, rules of thumb that can be used to calculate the indirect costs (Accounts 30-41) as a fraction of the direct costs. A literature review will be required to find the best algorithms. Engineering-economic textbooks often contain such Cost-Estimating Relationships (CER) for conventional industrial and chemical facilities.

A technique that was previously developed for Generation III+ plant field indirect costs is presented as an example. Field indirect costs comprise three categories of costs:

1. Fixed, one time charges for items such as purchase and erection of temporary construction facilities, fence, access road, or utility connections.
2. Scope related costs such as, tools, construction area cleanup, material handling and warehousing, and
3. Time related costs such as construction equipment rental, site cleanup, and temporary facility maintenance.

Actual cost data was analyzed and costs defined for the three components for a typical 1200 MWe project, Nuclear Island and BOP scope. An algorithm was developed to calculate the field indirect costs for any size plant. The algorithm for 1/1200 costs are as follows:

$NI = 5.09 \times 10^6 (P/1200)^{.33} + 0.48\ LN + 3.20 \times 10^5 (P/1200)^{.5}\ M$,

$BOP = 5.09 \times 10^6 (P/1200)^{.66} + 0.34\ LF + 3.20 \times 10^5 (P/1200)\ M$,

where:

P = Plant rating (MWe)

LN = Labor cost for Nuclear Island scope

LF = Labor cost for BOP scope

M = Construction duration (Months)
Similar algorithms can be developed for other indirect costs such as construction supervision, design services and PM/CM services.

5.7 Other life cycle cost elements.

Other life cycle elements that need top-down estimating techniques are the following.

Pre-construction costs: Typically only cost of land is included in this category. A cost per acre is sufficient definition of these costs. The area is to include the project site and any exclusion areas around the plant site.

Contingencies: If an integrated design/cost model exists, an uncertainty analysis can be used for contingency calculations. This is explained in Appendix A.

Interest During Construction: This is handled in the same way as for bottom-up estimating, except that, in the absence of detailed schedule information, a multi-year, cumulative (e.g., “S-curve”) spending pattern can be imposed on the TCIC.

Commissioning and Start-Up Costs: A CER can be developed from historical data that present start-up cost as a fraction of TCIC or even RD&D costs. A project that requires high spending on RD&D will probably also involve higher startup costs.

Operations: Some operations cost models exist for conventional reactor types. The ORNL O&M cost model (Bowers *et al.,* 1987) from the mid-1980s is one such model containing cost-estimating relationships based on water reactor experience. By the use of careful operations analysis, the EMWG and the system development teams should be able to develop new algorithms from old ones, as was the case with SEMER capital costs.

Fuel Cycle Costs: Any new reactor is likely to still use some of the materials and services that are already commercialized. Scaling might be required in the development of capital and operating costs for a new type of fuel fabrication or reprocessing facilities. The guiding principles would be the same as for developing CERs for the reactor, as described above. Chemical and metallurgical industry CERs should be useful.

D&D Costs: On bottom-up versus top-down D&D cost estimates, see (Pasqualetti and Rothwell, 1991). For many studies D&D costs are calculated as a fraction of the overnight costs. During the 1970s D&D was often assumed to be 10% of overnight nuclear power plant cost in constant money; recent D&D cost experience indicates that 10 to 33% may be more realistic. The *Guidelines* recommends assuming that D&D costs represent one third of Total Direct Costs.

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6. GROUND RULES FOR DETAIL BOTTOM-UP ESTIMATING

This chapter defines the bottom-up estimating guidelines. In Section 6.1 standard plant cost is differentiated from (1) one-time costs incurred during the RD&D stages and (2) the deployment stage with FOAK costs. Section 6.2 refers to the general assumptions underlying cost estimate preparation. Section 6.3 gives specific guidelines. Section 6.4 describes the requirements for estimating direct and indirect capital costs. Section 6.5 to 6.7 briefly outline the requirements for other project costs and will be expanded in later issues of these guidelines. Sections 6.8 and 6.9 provide detail estimating notes by discipline. Sections 6.10 to 6.13 briefly outline the requirements for other plants and will be expanded in later issues of these guidelines.

There are two basic reasons to deal with high-detail bottom-up cost estimating guidelines for Generation IV systems at an early stage in the RD&D/deployment path:

1. Some of the concepts are closely related to existing reactors for which detailed designs and cost estimates are available. Examples are the VHTR, which contains many of the features of the GT-MHR or the PBMR (Pebble Bed Modular Reactor). The SFR is also related closely to Japanese and French LMR concepts and to the PRISM/IFR concept developed by General Electric and Argonne National Laboratory. The SCWR builds on conventional water reactor technology. These three concepts should be able to move to detailed bottom-up estimating quickly.
2. It is useful to impose the concept of consistent "level playing field" cost estimating, using guidelines, at an early point in the RD&D program. As A/Es are engaged by the various design teams, they can become accustomed to the discipline imposed by the use of guidelines. If cost estimating conforms to the guidelines and is transparent to all design groups, it will have higher credibility and lead to better decision making.

6.1 Cost Categories

Costs are to be expressed in constant reference year dollars. The data tables for specific estimating parameters in this chapter use January 1, 2001, dollars). All technology development (reactor and fuel cycle RD&D) and prototype life cycle (proto-design, proto-construction, and proto-operations) are to be included in RD&D. A similar accounting structure can be imposed on prototype costs as for commercial plants; in fact, for competing prototype designs within a given concept some sort of cost estimating uniformity will be required to enable fair decision making. All categories may not be applicable for a given system (e.g., a prototype plant may not be needed for all advanced systems). All year-by-year RD&D costs should be reported as a "pre-commercial" category and should not be amortized in the LUEC. Another set of pre-commercial costs are the true FOAK costs that do not recur for subsequent plants (see Figure 1.1). The timing of all pre-commercial expenditures (cash flows) should be identified starting in 2005. Fuel cycle facility construction and operation costs, and the costs of existing fuel cycle materials and services, are discussed in Chapter 8.

The assignment of the costs into categories and their time distributions (discrete cash flows) allows these estimates to be combined (aggregated cash flows) for a concept through the first commercial plant as a function of time. If the transition plant costs and NOAK plant costs are included, the costs and time distributions may be combined as appropriate for a given plan of commercialization and allows all expenditures for a concept to be shown as a function of time. Details of the energy plant, fuel cycle facility, end-use (electricity or hydrogen production), and module factory capital costs should be given in the GIF COA format, which is explained in Appendix F.

A detailed estimate is one of the major milestones in the development of a project from concept to commercial operation. The first of the detail estimates is usually performed when the design progress reaches sufficient detail to support quantification of major project scope to commodity level. The required design status includes a comprehensive equipment listing that is supported by data sheets and P&ID's for all the process systems as well as the majority of non-process service systems. The facility structural details are sufficiently developed to support quantification of rebar densities for slabs, walls and other structural components. Electrical may be just at single line levels and the controls may be limited to control room and overall plant control concepts.

During project evolution detail estimates may be performed for initial budget, preliminary estimate and a final project estimate that may be basis for contractual budgets for the life of the project.

The estimate development is a team effort involving all lead personnel and for a typical nuclear power project requires a schedule of 3 months with a budget of approximately 2000 hours for project control personnel. A project estimator joins the team to prepare the instructions in the form of an estimate kick-off package.

6.2 General Ground Rules

See section 4 for discussion of general ground rules and assumptions that are applicable to both the bottom-up and top-down estimating techniques.

6.3 Specific Cost-Estimating Assumptions

The following assumptions will be used in developing the base construction cost estimates with the bottom-up detail estimating techniques.

1. For full bottom-up detail estimating process, the project scope definition is required to be at a fairly definitive level, sufficient to quantify not only the process equipment with data sheets but also most of the other commodities such as non-process equipment, pipe and valves, concrete and structural steel, HVAC and plumbing, electrical equipment, control room equipment.
2. Some of the commodities such as electrical cable or field instrumentation may not be sufficiently detailed at time of initiating a bottom-up detail estimate. Typical definitive project estimates include quantification of commodities such as cable and raceway that has been developed from equipment lists, circuit loading tabulations, instrumentation indexes and historical parametric data for average number of cables per circuit and average lengths.
3. For the direct cost, the subject plant will be quantified to commodity levels to the same level as the composite unit pricing and unit hour applications. For example the scope of structures and Concrete category of work will include quantification of commodities for 11. - Temporary form, 12. - Permanent form, 13. - Embedded metals, 14. - Reinforcing steel and 15. – Structural concrete. See the description of commodity codes in Appendix F – Code of Accounts. *Standard commodity COA with unit prices and unit hours will be available for use by each reactor design team***.**
4. The cost estimate entries for a given direct or indirect cost should be based on quantities of commodities/materials and equipment together with unit costs (see Tables 4.4 through 4.6). The installation costs should be based on quantities, installation rates (see Tables 4.7 through 4.9) and labor rates (see Tables 4.1 through 4.3) The basic cost algorithm for a particular account code is: Cost = Labor Costs (craft labor installation or structure construction) + Material Costs (concrete,

rebar, etc.)
+ Equipment Costs (including profit, taxes, and vendor engineering), where:
Labor Cost = (number of commodity units) x (unit installation rate hr/unit) x (unit labor cost/hr)
Equipment Cost = (number of units required in plant) x (cost per unit)
Material Cost = (number of units required in plant) x (cost per unit).

5. The unit installation rate describes how many hours it takes to install a given commodity unit, e.g., how many labor-hours it takes a crew to pour a cubic meter of concrete. A given account code may be the summation of several different equipment items, commodities, and types of craft labor involved.
6. Other coding of the estimate detail to support reporting requirements is to be included at the detail record level. Separation of nuclear and non-nuclear costs, unitized and common costs, recurring and non-recurring costs, etc. See discussion in section 4. - General ground rules and assumptions.
7. The quantification of the project scope can serve other project needs besides the estimate. Engineering work plans and staffing levels can utilize quantity of commodities with historic design production rates. Construction schedules depend on quantities of commodity and historic sustained rates of installation. COA coding can provide identifications for procurement, delivery and installation progress reporting. Eventual testing and startup activities are supported by the GIF COA coding that was initially defined during the bottom-up detail estimating process.
8. Each GIF COA detail at level 3 or lower is to be quantified and coded to the commodity detail with links to standard unit equipment cost or unit material cost and a standard unit hour rate for each commodity. Labor cost will be developed with a *standard composite cost per hour by category of work*. Each detail record will then be extended for a total cost.
9. Each detail record will carry coding to identify scope or quantity basis and basis for pricing equipment or material costs. The quantity basis will identify how the quantity was developed and the pricing basis will in most cases come from the standard commodity unit rates, except when a record is created with specific input that is unique to the project. This information will compile total project costs on a pricing basis and provide input to contingency cost assessments.
10. All construction will be estimated as direct hire, including specialty contractors. All field labor will be quantified and included as labor cost. Process equipment will be separated from all other equipment and material costs.
11. Estimate reporting requirements are discussed in Section 4.12.

6.4 Construction costs

The estimate kick-off package provides a recap of the project status and the ground rules for the estimate and discusses the methodology to be utilized for the quantification, pricing and labor development for all the components of the project scope.

Scoping documentation packages for each discipline estimator are assembled for an efficient start to the estimating effort.

An estimate kick-off meeting is conducted with attendance by all senior team members, including project management, engineering, procurement and construction (EPC). The meeting familiarizes everyone with the forthcoming effort to ensure appropriate support during the ongoing design effort with minimal disruption.

The estimate kick-off package includes:

1. Background – Brief history of project, placing the estimate deliverable in project perspective.
2. Intent – Describes the purpose and emphasizes the goals to be achieved.

3. Project scope – Describes the physical scope and the scope of services to be included for each major account.
4. Participant and Division of responsibility – Identification of the team members and the area of responsibility in support of the estimating effort.
5. Documentation of estimate basis – identifies the process for transmittals and documentation for all basis reflected in estimate.
6. Coding requirements – describes the project code of accounts and other type of information to be captured and coded during the estimating process for all project needs.
7. Services estimates – describes the requirements for development of estimates for services by each participating organization. Requirements for identification of tasks, staffing levels, durations, staff salary grades, manpower levels and other cost input.
8. Quantification of capital plant – This is the major section of the estimating effort supported by project control personnel and the package describes in detail, the available scoping basis and the methodology to be used for quantification each commodity for each discipline. The methodology identifies take-off items and those that will use some parametric approach for concurrence by the team. Use of reference project data is identified. The basis for each commodity quantity is to be identified by a code.
9. Labor development for direct costs – Requirements to utilize standard unit hours for subsequent application of productivity factors that have been determined for the site. Composite labor cost per hour were previously developed with input from construction and labor relations departments. The rates are calculated by category of work and estimating discipline.
10. Material and equipment pricing for directs – Guidelines for development of commodity unit prices for input to the estimating programs and subsequent input of scope quantity records. Use of reference project data is identified. The basis for each commodity unit cost is to be identified by a code. Procurement department support requirements are identified. Instructions for inclusions or exclusions for items such as tax, freight, escalation, warranty, spare parts or vendor support is provided.
11. Direct cost validation checks – Identifies requirements for comparison and reconciliation to previous estimates and actual project data, with tabulation of ratios and other parameter checks for validation of the current estimate at direct cost levels.
12. Field indirect cost –Identifies responsibilities for input and review for the indirect cost component such as support craft labor, temporary facilities and services, construction equipment, tools and supplies, non-manual staff, office costs, insurances, bonds and start-up support requirements. Identifies requirements for comparison and reconciliation to any previous estimates and/or reference project current or historic data. The requirements for tabulation of ratios and other parametric validation checks for the indirect accounts are defined.
13. Construction schedule – after the scope and quantities have been reviewed and finalized, the development of the project construction schedule is initiated with sequence and activities based on category quantities and the durations based on historical sustained rates of installation. The schedule is further developed to reflect the proposed project execution plan, construction work week, pre-assembly or modularization plans. The schedule is then resource loaded and optimized to produce staffing curves by craft, installation curves and cash flow requirements. A comparison to historic data supports the review process.
14. PM/CM and design costs – Level of effort staffing plans are to be developed for the PM/CM services. Design costs to be developed for remaining tasks based on quantity of commodity to be designed and budget rates of production. Other tasks are developed for level of effort and project schedule. Estimated salary grades are assigned for the tasks and summarized by COA. The resultant hours are extended with composite rates inclusive of benefits, taxes and insurance for total labor cost. Office space, equipment, travel, consulting services and other costs are quantified and priced at current

pricing levels. Fees, incentives and other costs are calculated based on estimate guidelines and contractual agreements.

15. Contingency cost and schedule – the estimate is to be summarized by the coded basis of scope and pricing and the project team provides input to a risk analysis that relates level of risk for cost overrun and the corresponding contingency. Management provides the acceptable level of risk and the probability of cost overrun. The assessment is to be in accordance with the estimating guidelines for the project.
16. Reviews – Identifies the series of reviews and supporting data to be presented. Initial reviews are conducted with engineering for all the project quantities, prior to proceeding with other cost development. Discipline reviews are conducted with EPC participation. Project schedule reviews are conducted with project construction and construction management departments. Total project cost estimate is then presented for review by management and supported by the EPC team. Final reviews would be presented by the project management team to corporate or governing agencies directors for final approval of the project budget.

6.5 Other Capital Cost Components

Other capital costs for accounts 30-60 – This scope of the estimate may be sequenced after resolution of the construction cost and schedule, which may become a basis for other capital costs. Describes the scope and pricing basis for each major account, including required documentation, summaries and comparison data. Reactor first fuel load costs may come from a separate estimating effort for the fuel fabrication facility.

6.6 Annual O&M Costs

At the conclusion of the capital cost and with input from that effort, the annual operating costs are to be developed with staffing levels by department, position and salary grade, consumables, lubricants and other supplies quantified for annual costs.

6.7 LUEC Calculations

The estimate details are to be summarized to level 2 COA and provide input to separate cost models for calculation of LUEC for capital cost, Fuel and annual O & M cost components.

6.8 Power Plant Detailed Bottom-up Estimating Notes

1. For full bottom-up detail estimating process, the project scope definition is required to be at a fairly definitive level, sufficient to quantify not only the process equipment with data sheets but also most of the other commodities such as non-process equipment, pipe and valves, concrete and structural steel, HVAC and plumbing, electrical equipment, control room equipment, and other commodities.
2. Some of the commodities such as electrical cable or field instrumentation may not be sufficiently detailed at time of initiating a bottom-up detail estimate. Typical project estimates include quantification of commodities such as cable and raceway that has been developed parametrically from available project data and historical information.
3. For the direct cost, the subject plant will be quantified to commodity levels to the same level as the composite unit pricing and unit hour applications. For example the scope of structures and concrete category of work will include quantification of commodities for 11. – Temporary form, 12. – Permanent form, 13. – Reinforcing steel, 14. – Embedded metals, and 15. – Structural concrete (See the description of commodity codes in Appendix F – Code of Accounts. *Standard commodity COA with unit prices and unit hours will be available for use by each reactor design team*)**.**

4. Other coding of the estimate detail to support reporting requirements is to be included at the detail record level. Separation of nuclear and non-nuclear costs, unitized and common costs, recurring and non-recurring costs, etc. See discussion in section 4. - General ground rules and assumptions.
5. The quantification of the project scope can serve other project needs besides the estimate. Engineering work plans and staffing levels can utilize quantity of commodities such as pipe, with historic design production rates. Construction schedules depend on quantities of commodity and historic sustained rates of installation. COA coding can provide identifications for procurement, delivery and installation progress tracking and reporting. Eventual testing and startup activities are supported by the GIF COA coding that was initially defined during the bottom-up detail estimating process.
6. Each GIF COA detail at level 3 or lower is to be quantified and coded to the commodity detail with links to standard unit equipment cost or unit material cost and a standard unit hour rate for each commodity. Labor cost will be developed with a *standard composite cost per hour by category of work*. Each detail record will then be extended for a total cost.
7. Each detail record will carry coding to identify scope or quantity basis and basis for pricing equipment or material costs. The quantity basis will identify how the quantity was developed and the pricing basis will in most cases come from the standard commodity unit rates, except when a record is created with specific input that is unique to the project. This information will compile total project costs on a pricing basis and provide input to contingency cost assessments.
8. Project indirect costs will initially be estimated with algorithms similar to the top-down estimating technique as described in Section 5.3.6. Subsequent project definition may include individual account quantification, unit pricing and staffing requirements development by task and duration. Composite costs per hour of labor may eventually reflect actual salary levels by grade of personnel.
9. Cost summaries based on standard unit rates and standard labor cost per hour will facilitate a direct comparison between alternative reactor concepts. The differences in direct cost will essentially be scope related for each reactor design.
10. *Appropriate cost factors to adjust the standard unit rates to each region will be developed with input by the individual design team and region*. These factors may be global for each cost component or be variable by category of work. It is unlikely that commodity level factors will be developed or required.
11. Direct cost summaries based on the region adjusted unit rates will be the basis for tabulation of FOAK and NOAK plant costs. Appropriate learning adjustment factors, amortization of non recurring costs and other considerations will produce level 2 COA summaries that in turn will provide input to other cost models for calculation of LUEC.
12. The relationship of project costs for the different reactor concepts may change for different regions. It is likely that labor productivity and composite cost per hour may contribute to an increase or decrease in the LUEC for the regions considered.
13. The resultant LUEC costs are the final cost comparison between the different reactor concepts. Other considerations such as proliferation or sustainability may contribute to the comprehensive evaluation of the recommended reactor system.

6.9 Discipline Notes for Scope/Quantity Development

The estimate kick-off package is to discuss major techniques that are to be utilized in developing the scope and quantities by discipline. The project team will consider the costs of providing any additional details versus contributions to accuracy and impact on plant costs. Other considerations for project use such as traceability, procurement status and construction tracking may optimize the estimating effort budget and schedule.

Category/Commodity	Methodology
CIVIL	
Site excavation	Develop for area of site
Structural excavation	Develop for all buildings
Structural backfill	Develop from excavation and construction scope
Trenching	Develop from site plan markup for pipe and duct bank
Temporary formwork	Develop from arrangement drawings
Permanent formwork	Develop from arrangement drawings
Embedded metals	Allowance ratio to volume of concrete by structural component
Reinforcing steel	Take-off sample ratio to volume of concrete by structural component
Concrete	Develop from arrangement drawings with use of average wall/slab thicknesses as necessary
Structural steel	Take-off or develop from arrangement drawings for process buildings, non-process buildings use allowance weight/building floor areas
Miscellaneous steel	Ratio to weight of structural steel
Liner plate	Develop with engineering definition
Roofing	Process buildings by take-off, other with allowances per floor area
Siding	Process buildings by take-off, other with allowances per floor area
Painting/coating	Develop from arrangement drawings marked up by engineering for type of system
Windows/doors	Take-off from arrangement drawings
Interior finishes & furnishings	Develop from arrangement drawings marked up by engineering
Non process buildings	Allowances of cost and hours per floor area, including services
MECHANICAL	
Process equipment	Per equipment list verified with P&ID’s
Non-process equipment	Per equipment list, P&ID’s and reference plant development
HVAC ductwork	Develop from engineering markup of arrangement drawings
Insulation	Develop for scope defined by engineering
PIPING	
Process system piping	Conceptual routing of pipe from P&ID and arrangement drawings
Utility system piping	Conceptual layout of utility piping systems on arrangement drawings or site plans, plus system equipment interconnections
Facility services piping	Plumbing and drainage systems conceptual layout mark up on arrangement drawings
Process systems valves	Take-off from P&ID’s including allowances for instrumentation root valves
Large pipe hangers	Average spacing, including use of multiple pipe hangers
Small pipe hangers	Not quantified. Included in cost of small pipe
Miscellaneous piping items	Not quantified. Included in allowance for miscellaneous piping operations ratio to large and small pipe
Pipe Insulation	Develop with pipe scope based on engineering definition for insulation requirements
ELECTRICAL	
Distribution equipment, DC and emergency power	Take-off from single line diagrams
Cable tray	Develop from conceptual tray layout marked up on arrangement drawings
Duct bank conduit	Develop from conceptual routing marked up on site plans
PC&I Exposed conduit	Develop from historical ratio of raceway to cable
Scheduled power cable	Develop for single line diagram distribution and connected loads with average length and average size distribution
Scheduled Control cable	Develop with historical ratio to connected loads, average length and average size distribution
Scheduled instrumentation cable	Develop with historical ratio to quantity of field instruments, average length and average size distribution
Grounding	Develop from conceptual layout mark up on site plan plus route length of cable tray

Category/Commodity	Methodology
Process buildings lighting	Reference plant ratio of commodities per floor area
Non-process building lighting	Not quantified. Included in costs per floor area
Yard lighting	Developed from conceptual layout marked up on site plans
Communication systems	Developed from engineering markup of arrangement drawings
Cathodic protection	Develop allowance from engineering system description and marked up site plans
Heat tracing	Develop allowance from engineering system description and quantification of piping systems
Radio system	Develop from engineering system description and markup of arrangement drawings for the antenna system
Security system	Develop allowance for system with engineering input and reference plant data
INSTRUMENTATION	
Plant protect. & control system	Develop costs with engineering capacity data and vendor input
Control room equipment	Develop from arrangement drawings and system data sheets
Local control panels	Develop from equipment list and reference plant data
Instrument racks	Design allowances by areas of plant
Field mounted instruments	Instrument index and take off from P&ID's
Control valves	Take off from P&ID's
Instrumentation bulks	Reference plant date ratio to field mounted instruments

Guidelines and parametric data to be developed for project scope that typically is not available at time of initial detail bottom-up estimate.

1. Reinforcing steel weight ratio to volume of concrete by structural component.
2. Embedded metals weight ratio to volume of concrete by structural component.
3. Service building allowance quantity of composite concrete per floor area.
4. Service building allowance architectural and services per floor area.
5. Miscellaneous steel quantity percentage of structural steel.
6. Architectural finish cost and hours per floor area by building.
7. HVAC system ductwork and controls cost and hours per building volume by building.
8. Small pipe quantity percentage of large pipe.
9. Pipe hangers percent cost and hours of large pipe.
10. Pipe insulation percent cost and hours of large pipe.
11. Piping miscellaneous operations percent cost and hours of large and small pipe.
12. Instrumentation bulks quantity ratio to field instruments.
13. Instrumentation control panels cost and hours per length of field panels.
14. Power, Control and Instrumentation (PCI) cable development guideline.
15. PCI cable connection quantity development guideline.
16. PCI exposed conduit development guidelines.
17. Non-metallic underground conduit quantity development guideline.
18. Lighting fixtures quantity, per floor area by building.
19. Lighting wire and conduit quantity, cost and hours per light fixture.
20. Lighting panels and miscellaneous equipment cost and hours percentage of light fixtures.
21. Communication systems cost and hours per floor area by building.
22. Security system allowance cost and hours.
23. Grounding system conceptual quantity, cost and hours development guideline.

6.10 Other Plants

Similar estimating process is applicable for estimating hydrogen production, desalination or other co-generation concepts. Summaries of the direct costs will be merged with the power plant direct cost, prior to estimating the indirect and owner accounts for the combined project. Level 2 COA summaries will provide input to other cost models for calculation of LUEC and Levelized unit product cost (LUPC).

6.11 Dedicated fabrication facility

Any dedicated factory proposed for fabrication of major equipment or structural modules should be estimated in detail for the construction costs as a separate project and a separate investment recovery. Annual ownership and operation costs should be estimated for the planned production capability or throughput. Amortization of the factory capital costs and operation costs are to be calculated for recovery over the planned production quantity and expressed as a percentage overhead cost relative to shop labor. All components manufactured at the factory will be priced inclusive of shop overheads with the amortization component. Process equipment and materials that will be built into the factory modules are to be priced without mark-up.

6.12 Fuel fabrication plant

Fuel fabrication facilities are to be sized to meet the projected fuel needs for the reactor concept and the nominal fleet size of 32 GW of plant capacity. Similar estimating process will be utilized to estimate the capital construction costs of the fuel fabrication plant. Separate estimates of the annual operating costs and production capacity will provide input to a separate cost model for calculation of levelized unit fuel cost (LUFC) including returns on the investment. The resultant costs will provide the fuel cost component for calculation of LUEC for the power plant. The first fuel load may be required prior to commercial operation of the dedicated fuel fabrication facility therefore the cost may be significantly higher if fabrication is a manual process.

6.13 Fuel reprocessing plant

Similar considerations as for the fuel fabrication plant except the schedule requirements are linked to the back-end of the fuel cycle. Separate estimates of the annual operating costs and reprocessing capacity will provide input to a separate cost model for calculation of levelized unit reprocessing cost (LURC) including returns on the investment. The resultant costs will provide the fuel reprocessing cost component for calculation of LUEC for the power plant.

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7. TOTAL CAPITAL AT RISK

This section provides the ground rules for preparing an estimate of the Total Capital Investment Cost (TCIC) of an energy plant. TCIC corresponds to the Total Capital At Risk figure of merit for the Generation IV Economic Goal: to have a level of financial risk comparable to other energy projects. The base and overnight construction costs, described in Chapters 5 and 6, are the starting point for costs developed in this section. The TCIC should be calculated in January 2001 constant dollars. In the present guidelines cost estimation inflation and escalation are excluded. This chapter discusses cash flow, IDC and contingency.

7.1 Cash Flow

If possible (most likely for bottom-up estimates) the cash flow (funding) requirements during the design, construction, and start-up period should be determined on a quarterly basis (four schedule increments per year) for the prototype, FOAK, and NOAK plants. Some concepts might not have enough detailed engineering and scheduling completed to report cost data by quarters. If this is the case, annual cash flows should be reported or a generic (e.g., "S-curve") cumulative distribution should be explicitly applied to the TCIC. The cash flow should be expressed in 2001 constant dollars, as are the overnight costs, and should indicate whether contingency costs are included. Contingency costs should be explicitly included in the cash flow data if it is not assumed that contingency cash flow is directly proportional to base construction cost cash flow. Time effects, such as escalation, should not be included in the cash flow, since estimates are to be prepared in constant dollars.

7.2 Interest During Construction (IDC)

Once money is raised and the construction payments begin, an accumulated return (interest) to the construction loan, investors, or bank must be accrued until commercial operation. This return is referred to as IDC. Usually, in the United States, the IDC rate is an average cost of money, including both equity and debt capital used to finance a project. Because methods of financing and taxation vary widely from country to country, the EMWG suggests that financing and taxation should not be used to discriminate among technologies at this stage of Generation IV system development. For comparison purposes, cost estimators using the present guidelines should calculate IDC at both 5% and 10% (see IEA and NEA, 1998).

Constant dollar interest will be calculated using the cash flow summaries developed following Chapter 5 and using discount rates of both 5% and 10%. All interest costs will be capitalized up to the commercial operation date using the following method. The equation is:

$$\text{IDC} = \sum_{j=1}^{j=J} C_j [(1+X)^{t_{op}-j} - 1],$$

where:

C_j	=	cash flow for year or quarter j, reflecting beginning-of-period borrowing
IDC	=	constant dollar IDC cost
J	=	number of periods (quarters or years of construction)
j	=	period #
t_{op}	=	quarter or year of commercial operation
X	=	real discount rate expressed annually or quarterly, as appropriate.

If the cash flow data developed does not explicitly contain contingency costs, then the interest calculated using the cash flow summaries must be adjusted by the ratio of the total overnight cost to base construction cost as:

$$\mathrm{IDC_{total}} = \frac{\mathit{pre-contingency}\ \text{cost} + \text{contingency}}{\mathit{pre-contingency}\ \text{cost}} \text{ x } \mathrm{IDC_{base\ cost}}\,.$$

If discounted cash flows, taken back to a reference year before construction, are used to calculate unit costs of electricity or other products, the IDC does not need to be calculated, since the discounting process automatically accounts for interest charges. IDC on equipment and facilities related to non-electrical energy products will be treated separately.

7.3 Contingency

Contingency applies to both bottom-up and top-down estimates. The difference is in the level of detail and level of mathematical/methodological complexity with which contingency is estimated. For Generation IV system cost estimation there are three contingencies to consider: base cost, schedule and performance.

7.3.1 Contingency on Base Cost plus Commissioning Cost (Account 52)

This contingency is an allowance applied to the base cost (sum or all items/activities in level one of COAs 1X thru 5X). It is usually calculated by multiplying the sum of the above accounts by a contingency factor. The factor is often represented as a percentage, for example if a 20% contingency has been applied, the base cost will be multiplies by 1.2 to reflect contingency.

Calculation of contingency is a complex subject. There are both deterministic and probabilistic methods for calculating its value. Deterministic methods, such the Hackney method (Hackney, 1997) require assessment of the maturity and complexity level of the various aspects of the project and cost weighting of the base estimate. The probabilistic approach requires statistical methods and the determination of uncertainty ranges for the key cost parameters affecting the costs. Also, a contingency must have a statistical level of confidence associated with it. As an example, a decision maker may want an estimate that gives him 90% confidence that the pre-contingency cost estimate plus the contingency lump sum or “overnight cost” will not be overrun. Appendix A describes the definitional, statistical, and economic issues associated with contingency determination.

7.3.2 Contingency on Schedule (Account 69)

Cost overruns for many projects are caused by construction schedule slippage: “time is money” and schedule slippage causes an increase in both base and financing (interest) costs. Since it is too early to have detailed construction schedules for Generation IV projects, calculation of the costs of schedule overruns or under-runs cannot be explicitly calculated by linking scheduling software, such as Primavera or Microsoft Project with cost uncertainty software, such as @Risk, Crystal Ball, or ORMONTE (Williams, 1989). The application of a contingency factor to the IDC is suggested as a means of representing the cost effects of schedule uncertainty (See Appendix A. Section 3.1.).

7.3.3 Contingency on Reactor Performance

Performance under-run is a major cause of unit cost overrun for energy projects. The major measure of energy production performance for an energy plant is the capacity factor (CF). If a new technology does not meet its capacity factor goal, less energy will be produced annually and all life cycle costs are distributed over less electricity production, thus the LUEC will be higher than predicted. A contingency or "performance degradation" factor (a multiplier on CF) will be calculated to reflect this concern (See Appendix A, Section 3.2).

7.4 Total Capital Investment Cost

The total capital investment cost, expressed in constant money, consists of the Total Overnight Construction Cost accounts 1X thru 5X (OCC) and capitalized financial costs account 6X (CFC). All components expresses in constant money:

$$TCIC = (OCC) + (CFC)$$

Where possible all costs should be expressed in constant dollars and separated into nuclear-safety grade, non nuclear-safety grade, and total cost in the more detailed accounting. Table 7.1 provides the format to be used in reporting total capital cost.

Table 7.1 Total Capital Cost Estimate Reporting Format (10^3 \$ of January 2001)

COA Number	COA Description	Nuclear-safety grade cost	Non nuclear-safety grade cost	Total cost
1X	Pre-Construction costs			
20	Capitalized direct costs			
21	Structures and improvements			
22	Reactor equipment			
23	Turbine equipment			
24	Electrical equipment			
25	Heat rejection system			
26	Miscellaneous equipment			
27	Special materials			
28	Simulator			
29	Contingency			
	Total direct construction cost (DCC)			
3X	Capitalized Indirect service (CIC)			
4X	Capitalized owner cost (COC)			
	Total indirect costs			
	BASE CONSTRUCTION COST (BCC)			
	Total (103$)			
	Specific ($/kWe)			
5X	Capitalized supplementary costs			
	TOTAL OVERNIGHT COST(OCC)			
	Total (103$)			
	Specific ($/kWe)			
6X	Capitalized financial costs			
	TOTAL CAPITAL INVESTMENT COST (TCIC)			
	Total (103$)			
	Specific ($/kWe)			

7.5 Capital Cost Component of the LUEC

Under the assumption of equal annual energy generation, the equation for calculating the constant dollar levelized capital cost can be expressed as:

$$LCC = (FCR \times TCIC)/E,$$

where:

LCC = Levelized Capital Cost in constant dollars, ($/MWh);
FCR = constant dollar Fixed Charge Rate (per year);
TCIC = Total Capital Investment Cost in constant dollars ($); and
E = annual electric energy generation for single unit (MWh/year).

A fixed charge rate is normally used to account for return on capital, depreciation, interim replacements, property tax, and income tax effects. The fixed charge rate is discussed in detail in Appendix B of Delene and Hudson (1993). The fixed charge rate can be calculated using the NECDB (ORNL, 1988) methodology as implemented in an IBM type PC code (Coen and Delene, 1989). Since for Generation IV cost estimation tax and depreciation considerations are being ignored at present, the constant dollar fixed charge rate is calculated as a capital recovery factor, or amortization factor, as one would use to calculate the amortization of a loan:

$$FCR = X/[1 - (1 + X)^{-Lecon}],$$

Where:

X = real discount rate (5% and 10 %); and
L_{econ} = economic or regulatory life of the plant (years), assumed to be the same as the number of years of commercial operation.

The TCIC, which is the sum of the overnight cost plus the cost of the construction loan, is being "rolled-over" to a mortgage-type loan that recovers all of the capital investment (principal plus interest) over the operational or regulatory life of the plant. As more robust plants capable of 50+ years of regulatory life are constructed, and as investors demand shorter payback periods, the future capital recovery period is likely to be considerably shorter than actual plant operating or regulatory lifetimes.

In the present guidelines, 5% and 10% real rates of return are used because they are considered representative of the average cost of capital for most nuclear energy plant owners. The 5% real discount rate is appropriate for plants operating under the more traditional "regulated utility" model where revenues are guaranteed by captive markets. The 10% real discount rate would be more appropriate for a riskier "deregulated" or "merchant plant" environment where the plant must compete with other generation sources for revenues.

The levelized cost of capital (expressed in $/MWh) for nuclear plants is usually the largest component of the overall cost of electricity, mainly because the capital facility must be extremely robust, have adequate safety systems, and be built to very high Q/A standards. Other unit cost components are lower, especially fuel, since nuclear energy plants produce a large amount of energy from a very small volume. This differs from fossil plants, where fuel is usually the dominant unit cost component.

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8. FUEL CYCLE COST

8.1 Introduction

If the levelized lifetime cost methodology is adopted for estimating total generation cost, adopting the same approach for fuel cycle cost ensures consistency. The cash out-flow for fuel cycle material and services commences before the reactor starts to generate electricity and continues well after the reactor ceases operation. The exact timing of payments for uranium, fuel fabrication, reprocessing, etc., depends on the fuel cycle chosen and the associated lead and lag times for each of the fuel cycle components.

In order to calculate the overall fuel cycle cost, the magnitude of each component cost F_i and the appropriate point in time when it occurs must be identified. The quantities and specifications of the fuel required are derived from the reactor characteristics and will be provided by system development teams; these quantities of material and services must be adjusted to allow for process losses in the various component stages of the nuclear fuel cycle. Each component cost can then be calculated by multiplying the quantity of material or service by the unit price (cost to the owner/operator).

$$F_i(t) = M_i . P_i(t)$$

where:
M_i = Quantity of material/service required for step i
$P_i(t)$ = Price of material/service i at the time t

In this version of the guidelines, it is assumes that at equilibrium, fuel cycle requirements and performance can be averaged over economic the lifetime of the plant. With this assumption, the levelized fuel cycle cost can be calculated using the formula below:

$$\sum_i \sum_{t=t_0-T_1}^{t=t_0+L+T_2} \frac{F_i(t)}{(1+r)^{(t-t_0)}}$$

where:
t_0 = reference date (generally commissioning date)
L = reactor lifetime
T_1 = max. value of lead time (in front-end)
T_2 = max. value of lag time (in back-end)
r = discount rate

The unit cost factors ($/kg of material) that are addressed in this chapter will depend on the following factors:

- Fissile/fertile materials used (NATU, LEU, HEU, MOX, U-Th, etc.).
- Enrichment of fissile materials.
- Other materials in the fuel assemblies (Zr, graphite, etc.).
- Services required for producing the needed materials (mining, milling, conversion, enrichment, fabrication).
- Costs of spent fuel disposal or of reprocessing and HLW (incl. TRU waste) disposal.

The availability of existing fuel infrastructure or the need to create new infrastructure is a key driver of fuel cycle unit costs.

8.2 Costing of Commercially Available Fuel Cycle Services and Materials

The following paragraphs give an overview of the costs of the different fuel cycle steps as reported in literature as well as possible tendencies for future developments of these cost as perceived at present, according to a recent NEA study on trends in the nuclear fuel cycle (NEA, 2002).

The very low natural uranium prices prevailing at the end of the 20th century, i.e., about 20 $\$/kgU_3O_8$, imposed economic difficulties even for the very best mines. While a continued supply of uranium from materials declared excess to national security by the US and Russia is likely to maintain this low price in the short term, a rebound of demand for newly mined natural uranium (due to draw-down of inventories and other market factors) could result in price increase. Indeed, significant uranium price increase occurred between 2003 and 2005. A minimum price range of 40-50 $\$kgU_3O_8$ likely would be needed to allow the mining industry to expand production to cope with a renewed growth of nuclear power capacity.

The conversion market, in essence based on chemical processes, has experienced a period of decreasing prices in the past years. The present price for long-term contracts for conversion of natural uranium oxide to uranium hexafluoride for enrichment lie in a nominal range of 4 to 6 $/kgU, while spot prices in 2000 (reported by NUKEM) lie in the range of 2.45 to 3.85 $/kgU. In the longer term, an upper bound of about 8 $/kgU may be expected.

As indicated above, the enrichment market has seen significant changes and is characterized by persistent over-capacity. This has resulted in a present price range of about 80 to 100 $/SWU. In the years to come, the market situation will continue to be influenced by highly-enriched uranium coming from disarmament programs, which is likely to induce downward pressure on enrichment prices.

Existing excess capacities in a highly competitive market have led to a drastic decrease in the UOX fabrication price, currently in a range between 200 and 300 $/kgU. With respect to the future development of the UOX fabrication price, the most important factors are technical developments influencing the fuel assembly demand (e.g., burn-up increase), continued efforts to further improve the efficiency of the manufacturing processes, as well as effects resulting from mergers of suppliers (e.g., reduction of excess capacities). In contrast to all other steps in the fuel cycle, fuel assembly design and fabrication also influences the specific costs of the other steps and, being the link between fuel cycle and nuclear power plant, may influence the remaining elements of the energy generating costs as well.

Costs for interim storage of spent UOX-fuel were also reported ranging from 40 to 80 $/kgU, where an interim storage time of two years is standard. Another source reports a cost for “away-from-reactor” wet storage of LWR fuel assemblies (in 1987$) to be a fixed 50 $/kgHM plus 5×T $/kgHM within a range of plus or minus 50%, where T(years) is the period of storage (NEA, 1989). Spent-fuel transport costs have been reported in many publications to be around 50 $/kgHM (40 to 60 $/kgHM).

Concerning reprocessing, the situation is different because the market is characterized by a situation with only two main commercial vendors relying on long term contracts with certain utilities. New contracts, making use of existing facilities, seem to indicate significant price reductions, taking benefit from the accumulated experience and reflecting that much of the investment costs have been amortized. In the future, the new plants would benefit greatly from the large experience that has been gained during the last decades, allowing simplifying the plants, decreasing their size, reducing maintenance requirements, etc. If, however the separation of selected nuclides (e.g., minor actinides) would be implemented, the cost could be increased relative to conventional U/Pu separation.

The conditioning and geological disposal of high-level waste (vitrified or spent fuel) does not yet rely on industrial experience and most costs quoted are based on estimates and detailed design studies in the different countries. Disposal of HLW is claimed often, by the countries that have nuclear power programs, as being too important to be left to the producers of the wastes alone and is considered a national responsibility, with the waste producers paying for the proper disposal of the waste. The handling and disposal of this waste is paid by provisions established by the utilities, while national waste management agencies have been established to perform the disposal operation. As the geological conditions and amounts of waste differ according to the national nuclear energy programs, the cost ranges are wide.

Important technical factors that affect costs are the size of the system, time schedule of the disposal project, geological medium, and the barrier system chosen. Next to these technical factors, social and political issues also impact costs. These will affect the siting and licensing process as well as the overall waste management policy. Studies show the variability of normalized costs depending on the size of the system and the waste management policy (NEA, 1993). Recent studies in Belgium indicate that a very important decrease in cost has been achieved over the past years (NIRAS, 2000). Disposal costs are estimated to be some 0.2 M$/m^3$ of waste packaged for disposal or less for spent UOX fuel, and about 0.5-0.7 M$/m^3$ for HLW (Charpin et al., 2000). It is important also to consider that the volume of HLW conditioned in glass is about ten times lower than the equivalent spent fuel in a metallic canister. Thus, expressed as cost per kWh of electricity produced, disposal as vitrified HLW is cheaper than disposal as spent fuel. Regarding spent MOX fuel, the cost depends mainly on the decay heat level because a higher decay heat level demands significantly wider spacing of the waste containers. In the case of rapid disposal (i.e., after a short decay time) the heat level could be three times higher, and the cost higher by a similar ratio, than for disposal after a significant period of storage and decay.

Table 8.1 Expected range of unit costs for uranium and fuel cycle services*

Parameter	Unit	Lower bound	Upper bound	Mean	Description
$Cost_{U}$	USD/kgU_3O_8	20	80	50	Unit cost of natural uranium
$Cost_{Uconv}$	USD/kgU	3	8	5.5	Unit cost of conversion
$Cost_{Uenr}$	USD/SWU	80	120	100	Unit cost of enrichment
$Cost_{UOXfab}$	USD/kgUOX	200	300	250	Unit cost of UOX fuel fabrication
$Cost_{MOXfab}$	USD/kgMOX	1 000	1 500	1 250	Unit cost of MOX fuel fabrication
$Cost_{UOXrepro}$	USD/kgHM	500	900	700	Unit cost of UOX fuel reprocessing (for less than 20-30%of MOX-fuel)
$Cost_{MOXrepro}$	USD/kgMOX	500	900	700	Unit cost of MOX fuel reprocessing
$Cost_{UOXintstore}$	USD/kgUOX	100	300	200	Unit cost of UOX fuel interim storage (2 years)
$Cost_{UOXgeo}$	USD/kgUOX	300	600	450	Unit cost of UOX fuel geological disposal
$Cost_{HLWgeo}$	USD/kgUOX	80	200	140	Unit cost of HLW geological disposal
$Cost_{FR\text{-}MOXfab}$	USD/kgMOX	1 200	2 000	1 600	Unit cost of FR-MOX fuel fabrication (including fertile blankets)
$Cost_{FR\text{-}MOXrepro}$	USD/kgMOX	1 000	2 000	1 500	Unit cost of FR-MOX reprocessing (+200 to 300 USD/kgFR-MOX for blankets)

* Note that some values were converted from Euro to dollar of the United States, using a conversion of 1 € = 1 $.

Table 8.1 gives an overview of the lower and upper bounds of unit costs expected to be applicable in the short to medium term for conventional, commercially available materials, and fuel cycle services. The table will be completed when additional data become available. Over the long term, beyond 20 years, cost evolutions are likely to follow the historic trends, i.e., decreasing in constant terms. The magnitude will depend, however, on aspects related to the vitality of the nuclear industry. Depending on the special boundary conditions, fuel cycle costs for individual countries, and, in addition, for the individual utilities within a country, may deviate significantly from such generic figures. For preliminary cost estimates within the GIF program the mean value should be used.

8.3 Costing of Fuel Cycle Services and Materials Not Available Commercially

For some concepts fuel cycle cost information will be required for fuel types or fuel services that are not now commercially available. For these there may be little cost or price information. The unit costs for these fuels ($/kgHM) or services ($/unit of fabrication, reprocessing, etc.) initially will be calculated with a top-down approach. The EMWG will start with information from the Generation IV system designers and sources within the DOE/NE Advanced Fuel Cycle Initiative (AFCI) program. A unit cost can be built from the following data:

- Fuel Cycle facility base and owner's costs.
- A design/construction duration (for IDC calculation).
- Contingency.
- The annual production from the plant, e.g. kgHM/yr.
- The number of years of commercial operation.
- Annual operating costs ($M/yr).
- An interim replacement rate of capital.
- The cost to D&D the plant.
- The number of years the D&D fund is to be collected.

The cost summation and levelization algorithms are much the same as for the reactor. It is realized that most concepts will need to start with top-down estimating based on reference fuel cycles. The most likely fuel cycles to need this type of analysis are fuel fabrication facilities for advanced reactor types, fuel reprocessing facilities, and special separation facilities, such as for actinides.

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9. CALCULATION OF THE LUEC

9.1 Levelized Unit Electricity Costs

This chapter discusses Operations and Maintenance (O&M) and Decontamination and Decommissioning (D&D) costs and how they are included in the calculation of the Levelized Unit Electricity Costs (LUEC). Levelization divides the annual costs of operation over total annual production, allowing comparison with other electricity generating technologies. The LEUC corresponds to the Generation IV economic goal of having a life-cycle cost advantage over other electricity sources. (The LUEC can be generalized to Levelized Unit Energy or Unit Product Costs for non-electricity products such as hydrogen, process heat or desalinated water.) The are four primary components of the LUEC: (1) annual capital expenditures, discussed in Chapter 7; (2) annual fuel expenditures, discussed in Chapter 8; (3) annual O&M costs; and (4) annual D&D costs. Annual O&M costs and annual D&D costs are discussed later in this chapter. Annual D&D costs may be accounted for either as part of the total capital investment cost of nuclear energy systems, within O&M costs, or as a separate category – the latter approach will be used in EMWG models.

The LUEC is defined by the OECD (see IEA and NEA 1998) as:

$$LUEC = \Sigma\ (I_t + FUEL_t + O\&M_t)\ (1 + r)^{-t}]\ /\ \Sigma\ [E_t\ (1 + r)^{-t}]$$

where:
I_t = annual capital expenditures;
$FUEL_t$ = annual fuel expenditures; and
$O\&M_t$ = annual O&M expenditures.

Substituting the levelized cost of capital (LCC) for levelized annual capital expenditures, adding D&D, and assuming constant annual expenditures and production, the formula becomes:

$$\begin{aligned} LUEC &= LCC + \Sigma\ [(FUEL + O\&M + D\&D)\ (1 + r)^{-t}]\ /\ \Sigma\ [E\ (1 + r)^{-t}] \\ &= LCC + [(FUEL + O\&M + D\&D)\ \Sigma\ (1 + r)^{-t}]\ /\ [E\ \ \Sigma\ (1 + r)^{-t}] \\ &= LCC + [(FUEL + O\&M + D\&D)/E] \end{aligned}$$

As shown in this chapter,

$$LUEC = LCC + (FUEL/E) + LCOM + LCDC$$

9.2 O&M Costs

This subsection provides guidance on the determining the non-fuel O&M costs. The O&M costs start with commercial operation and continue throughout the operating life of the plant. Generation IV systems could conceivably have 60 years or more of operation.

Some O&M costs, such as those for materials and supplies, can partially depend on the amount of energy generated by the plant. These variable costs should be added to the fixed costs, which are independent of generation, to arrive at a total annual O&M cost. Since we are assuming a fixed amount of electricity generation per year, both fixed and variable costs will be expressed as annual costs.

The O&M cost estimate should provide, if possible, the detail shown in Tables 9.1 and 9.2. The COA descriptions are shown for each category in the tables. Site staff requirements should also be reported as shown in Table 9.3. For multi-unit plants, the annual O&M costs and staffing requirements should be specified for each unit and staffing requirements non-associated with a specific unit ("common").

The O&M cost estimate should be the most likely cost and expressed in constant dollars for the reference year, i.e., January 2001. Some O&M costs are design independent and/or owner related. Data for these factors are provided below (Tables 9.4 and 9.5) and should be used in the development of the annual O&M costs. Contingency should be built directly into the O&M costs rather than carried as a separate account; however, it can be calculated by the same methods as used for capital cost contingency (see Appendix A).

The tables below are based on U.S. practice. Some O&M categories shown here may not apply to some Generation IV systems or in countries outside the U.S. International GIF members using the guidelines should modify them to fit their national practice, keeping a similar level of detail. Note that IAEA Account 830 (Charges on Working Capital) is not needed if estimators assume that positive and negative cash flows are equal in constant money over the operating years. Also, a new account can be added for interim large equipment replacements. Normally these costs are capitalized for large items and not experienced every year. For Generation IV system cost estimation an average annual interim replacement rate (% of base cost experienced per year) can be assumed and expressed in $M/year.

Annual on-site staff salaries in the United States are shown in Table 9.3 with an additional allowance (e.g., 15%) for social security tax and unemployment insurance premiums. For off-site technical support, an average annual salary of $74 000/person (2001$) should be assumed with an additional 70% added to the total (plus social security tax and unemployment insurance and a 60% overhead allowance for office space, utilities, and miscellaneous expenses). These on-site and off-site staff salaries are the same as shown in (Delene and Hudson, 1993), but adjusted for inflation from 1992 to 2001 using the U.S. Gross Domestic Product implicit price deflator (See Table 4.11). The pension and benefits account (800A) that includes workman's compensation insurance should be calculated as 25% of the sum of on-site and off-site direct salaries (excluding off-site over-head). If not included elsewhere, appropriate utility overhead and G&A costs can be added to this annual salary sum to obtain a full staff salary.

Table 9.1 Annualized O&M COA description

GIF COA Number	Description
710 Operations and Maintenance staff	Includes all O&M personnel assigned to the plant site. See Table 7.3 for typical categories.
720 Management staff	Includes all management personnel assigned to the plant site. See Table 7.3 for typical categories.
730 Salary related costs	Costs of pensions and benefits, including worker's compensation insurance, provided for the on-site and off-site staff. The method of calculation will vary by nation. In some countries these are "social" costs. (Note: These can also be imbedded in accounts 710 and 720 above.)
740 Operations chemicals and lubricants	Can consist of a mix of variable and fixed costs. Includes non-fuel items such as resins, chemicals, make-up fluids.

GIF COA Number	Description
	Includes costs of management and disposal of operational radioactive waste.
750 Spare parts	Purchased spare parts for operations of plant.
760 Utilities, supplies, and purchased services	Consumables operating materials and equipment, rad-worker clothing, office supplies. Can consist of variable and fixed costs. Consists of materials and other unrecoverable items such, small equipment and tools required for maintenance. In the U.S. these accounts include NRC annual fees and review costs, as well as other routine safety, environmental, and health physics inspections. Other nations' annual costs for this category will depend on their regulatory environment. Also includes purchased activities by personnel not assigned full time to the plant site; e.g., safety reviews, off-site training, environmental monitoring, meteorological surveys, power planning, fuel studies, and other owner home office activities directly supporting the plant. Some plants now use off-site crews for "contract refueling".
770 Capital plant upgrades	Total cost of large capital item that must be purchased after commercial operation start (e.g., steam generator replacement), averaged per year over the economic lifetime of the system. Can be estimated as a % of the base cost per year.
780 Taxes and Insurance	Costs for commercial and government liability insurance, property damage insurance, and replacement power insurance. Includes property taxes, sales tax, and any other taxes that can vary by country.
790 Contingency Annualized O&M costs	Allowances for contingency costs for the desired confidence level of O&M costs. (Can be embedded into 7XX categories above this eliminating the need for 790)

Table 9.2 Annual O&M cost format for multi-unit plants

	2001 $/year			
Direct Power Generation	1st Unit	2nd Unit	Other Units	Common
710. O&M-site staff				
720. Management staff				
730. Salary related costs				
740. Operation chemicals, lubricants & radwaste management				
750. Spare parts				
760. Utilities, supplies and purchased services				
770. Capital plant upgrades				
780. Taxes and Insurance				
790. Contingency				
Total annual O&M costs				

Table 9.3 On-site staff requirements

Category	Salary 2001 $/year	Number of persons		
		1st Unit	2nd Unit Other	Common
Plant manager	145 300			
Administrative Division				
Manager	101 200			
Environmental control	64 300			
Emergency plant public relations	64 300			
Training	70 300			
Safety and fire protection	59 600			
Administrative services	38 600			
Health services	38 600			
Security	34 700			
Subtotal				
Operations Division				
Manager	101 200			
Shift supervision	74 600			
Shift operators	62 600			
Results engineering	62 600			
Subtotal				
Maintenance Division				
Manager	101 200			
Supervision	69 200			
Diagnostic engineering	62 600			
Crafts (Mech., Elect., I&C, ISI)	49 200			
Annualized peak maintenance	49 200			
Annualized refueling	53 200			
Radwaste	49 200			
Quality Assurance	53 200			
Planning	53 200			
Grounds and housekeeping	35 100			
Warehouse	45 300			
Subtotal				
Technical Division				
Manager	101 200			
Reactor engineering	74 600			
Radio and water chemistry	69 200			
Licensing and reg. assurance	63 900			
Engineering	63 900			
Technicians	51 900			
Health physics	53 400			
Subtotal				
Total staff				

Table 9.4 Annual insurance premiums for medium-sized (350-700/1400 MWe) advanced nuclear plants (in January 2001 dollars)

	Number of units per site			
	1	2	3	4
Public liability				
Commercial ($200 million)	$ 600 000	$ 900 000	$1 200 000	$1 500 000
Self insurance	-0-	-0-	-0-	-0-
Plant property damage				
Primary ($500 million)	2 835 000	4 335 000	5 836 000	7 337 000
Secondary ($600 million)	1 429 000	1 667 000	1 906 000	2 144 000
Total	$4 864 000	$6 902 000	$8 942 000	$10 981 00

Annual nuclear regulatory fees in the United States, based on information on the USNRC web site at www.nrc.gov/reading-rm/doc-collections/cfr/part171/part171-0015.html are approximately $3 million per year (2001$) per unit.

Estimates of annual premiums in the United States for nuclear plant insurance for medium-sized (350-700 MWe) advanced nuclear plants are provided in Table 7.4 and adjusted for inflation from Delene and Hudson (1993). Finally, other administrative and general expenses should be calculated as 15% of the direct power generation accounts (i.e., 15% of the sum of on-site staff, maintenance materials, supplies and expenses, and off-site technical support costs).

The constant dollar levelized O&M cost is the sum of the annual cost, OM, in each category above divided by the average annual electricity production, E, in MWh. This assumes that each year of operation has the same constant dollar cost, OM, and the same amount of annual electricity production (these are simplifying assumptions):

$$LCOM = OM/E$$

9.3 D&D Costs

Decommissioning of nuclear facilities covers the management and technical actions associated with the end of operation and withdrawal from service. Decommissioning activities start after the end of the technical life of the facility, but usually the funds for covering decommissioning expenses are accumulated while the plant is in operation, as is the common practice in the U.S.

9.3.1 U.S. Decommissioning Experience

Recently, D&D costs for operating nuclear energy plants, nearly all PWRs and BWRs, have been estimated for U.S. plants and are seen to vary from $300 million to $450 million, as shown at web site: http://www.nrc.gov/reactors/decommissioning/funding.html.

It is recommended that a typical value of $350 million US$ of 2001, be used as the radiological decommissioning cost of a single unit of a water reactor at a nuclear energy plant. This does not include dismantling costs or the costs of restoring the site to unrestricted use. In addition, a default minimum cost**,** that is a function of unit size, has also been defined. The default values are based on the USNRC minimum prescribed decommissioning costs developed by PNL (to release the site from NRC regulation). Separate minimum costs as a function of unit thermal output were prescribed for PWRs and BWRs. For this edition of the guidelines, the previous relations were increased by the rate of inflation since 1992. The minimum cost equations are given below.

PWR: Cost (million \$) = 173 + 0.024 (P-1200)
BWR: Cost (million \$) = 220 + 0.024 (P-1200)
Other: Cost (million \$) = 197 + 0.024 (P-1200)

where P = unit (block) thermal power MWth. Costs are constant at the 1200 MWth and 3400 MWth values for power levels below 1200 MWth and above 3400 MWth. These costs are assumed to increase at the rate of inflation.

For reactor types other than BWRs or PWRs an average value should be used based on design team's estimates. In absence of detailed estimates, estimators can use a "rule of thumb" that the total constant dollar decommissioning cost is 33% of the total direct capital cost. Contingency should be built directly into the D&D costs rather than carried as a separate account; however, it can be calculated by the same methods as used for capital cost contingency (see Appendix A).

Normally in the United States it is assumed that an external sinking fund consisting of high-grade tax-free bonds is established to accumulate the funds necessary for decommissioning. For Generation IV cost estimation, 5% and 10% real (not including inflation) discount rates will be assumed for a D&D sinking fund. For consistency of the analysis, it is assumed that the D&D fund will be accumulated over the plant's economic life. The constant dollar sinking fund formula can be used to calculate the required annual constant dollar payment:

$$LDDP = CDD \times SFF(X_{real}, L_{econ}),$$

where:
LDDP = the annual constant dollar payment made to the D&D sinking fund;
CDD = estimated decommissioning cost in reference year constant dollars;
$L_{econ.}$ = life of the plant assumed for fund accumulation;
X_{real} = the real discount rate; and
SFF(r, t) = sinking fund factor at rate r for t years, that is $SFF(r, t) = r/[(1+r)^t - 1]$.

Following the treatment used for O&M costs, the levelized D&D cost can be expressed as:

$$LCDC = LDDP/E$$

9.3.2 International Decommissioning Experience

In most countries, the regulator requires operators/owners of nuclear facilities to accumulate a decommissioning fund on the basis of decommissioning cost estimates that are audited by regulators and/or the government. Therefore, decommissioning costs have been published and analyzed in many national and international studies. The data available on decommissioning costs include: feedback from experience on completed decommissioning projects; ongoing projects; model calculations; and scaling of real costs taking into account reactor size, site, and type.

There are large differences in the national policies and industrial strategies adopted in decommissioning projects or assumed for cost estimation. The resulting variability of decommissioning costs has been recognized in all international studies. However, the analyses identify cost drivers and provided reasonable formulas to estimate decommissioning costs for planning and funding purpose.

The last NEA study on decommissioning policies, strategies, and costs (NEA, 2003) showed that decommissioning cost estimates reported remain below $500/kWe for nearly all water reactors covered in the analysis and, in average, decommissioning cost was estimated at about $350/kWe. This result is consistent with the Guideline's assumptions.

The study showed also that labor costs generally represent a significant share of total decommissioning costs, ranging from 20 to 40%. Two cost elements were found to represent a major share of total costs: dismantling and waste treatment/disposal, accounting for around 30% each. Three other cost elements were found to each represent another 10% of the total: (1) security, survey, and maintenance; (2) site cleanup and landscaping; and (3) project management, engineering, and site support. Other cost items were found not to exceed 5% of the total cost.

For Generation IV systems, D&D costs will likely vary depending on the reactor type and size. At the first stage of model development (top-down estimating) within EMWG, a generic assumption seems to be the best way to estimate undiscounted decommissioning costs. Once the Generation IV system designs become more precise, a bottom-up approach will be adopted to estimate D&D costs more precisely. At that stage, the standardized list of cost items proposed by international organizations (EC, IAEA, and NEA., 1999) could be a useful framework.

References

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IEA and NEA, 1998, *Projected Costs of Generating Electricity*: *Update 1998*, OECD.

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NEA, 2003, *Decommissioning Nuclear Power Plants: Policies, Strategies and Costs*, OECD.

10. UNIT COST CALCULATIONS FOR NON-ELECTRICITY PRODUCTS

Nuclear energy systems, and in particular Generation IV systems, can deliver non-electricity products, such as desalinated water, hydrogen, or heat, instead of, or together with, electricity. These non-electrical applications are described in, for example, IAEA (2002) and NEA (2004). The following sections address how to determine the cost of non-electricity products in the case of a system dedicated to one non-electricity product and in the case of a system producing electricity and other products.

Where nuclear energy systems are dedicated to one product, for example, potable water at a stand-alone desalination facility or hydrogen at a VHTR coupled with a sulfur-iodine thermo-chemical plant, all costs can be allocated to the single output. In these cases, the levelized unit cost of the product can be calculated following the method described in previous chapters of these Guidelines, adapting the COA to include the equipment and other items required for the balance of plant to produce desalinated water or hydrogen.

Where nuclear energy systems produce multiple products, each of which is sold in a fully competitive market, as is usually the case for electricity, market prices can be used to determine whether total costs are less than total revenues, i.e., whether a joint-product nuclear energy system is competitive. Allocating common costs, such as reactor cost, raises problems in that case and can affect significantly the economy of each product.

10.1 General Accounting Guidelines

10.1.1 Capitalized Direct Costs

The GIF COA provides a structure for reporting cost elements with a prefix designating the particular plant type. Code A designates an electric plant, while codes B through F designate other product plants, such as D for desalination plant or E for hydrogen production plant. The COA for the desalination plant is based on ESCWA/UN, 2001, p. 77-82. More details on non-reactor capital cost estimates are presented in Section F.5 and Table F.1 in Appendix F.

The GIF COA dictionary provides details of the COA structure for all plants. The COA level 1 codes are consistent across all plants. Level 2 codes differ only for the capitalized direct costs for accounts 22 and 23. Level 3 begins to differentiate the details that are unique to each type of plant, especially the Capitalized Direct Cost accounts within codes 22 and 23. Sample tabulations of COA structures for different types of plants are provided in Table F.1 in Appendix F.

Plants that combine a reactor with facilities to produce non-electricity contain the reactor plant systems within Account 22, similar to the nuclear electric production plant (Plant A). Top-down, or in some cases bottom-up, estimating methodology can be used in conjunction with reference plant data, similarly to the approach described for the electric plant in other sections of these Guidelines.

10.1.2 Other Capitalized Costs

Other capitalized costs are estimated with the methodology described above for nuclear power plants. The project execution plan, together with project schedules and construction plans, will provide the basis for estimating field indirect costs in accounts 31 through 34. Separate detailed estimates of design and project management – services accounts 35 to 38 – are estimated for the production plant in a similar way as for the electricity generation plant.

Capitalized Owner Costs (Code 4), Capitalized Supplementary Costs (Code 5), and Capitalized Financial Costs (Code 6) are estimated for the specific production plant, including supply of chemicals or raw materials as discussed in other sections of these Guidelines

10.1.3 Annualized Costs

Annualized Owner costs (Code 7), Annualized Supplementary costs (Code 8) and Annualized Financial costs (Code 9) must be estimated and accounted for, as discussed in other sections of these Guidelines, for the non-electric product plant.

10.1.4 Levelized Unit Product Cost

For single product plants, cost summaries at COA level 2 will provide input to other cost models for calculation of Levelized Unit Product Cost (LUPC), similar to LUEC calculations for electricity costs. For example, Levelized Unit Water Cost can be expressed in dollars per cubic meter ($\$/m^3$).

10.2 Allocation of Common Costs in Joint Production Systems

Although there is a vast literature on how to allocate common costs in nuclear energy systems, there is no clear consensus. The present Guidelines recommend the simplest method, known as the "power credit method". This has been adopted by the IAEA in DEEP (Desalination Economic Evaluation Program) to evaluate the economics of nuclear desalination (IAEA, 2000).

10.2.1 Allocating Joint Costs of Electricity and Desalination

The IAEA DEEP Program calculates the cost of water and power for single as well as dual-purpose plants (IAEA, 2000). The latter is evaluated using the power credit method which is the most commonly used. It is based on the comparison between the dual-purpose plant and an imaginary reference single purpose power plant using an identical primary heat source, in the present case nuclear steam supply system (NSSS).

The amount of net energy generated by the reference single-purpose plant (E) and total expenses incurred (C) are calculated first, from which the cost per saleable kWh (C_{kWh}) is derived ($C_{kWh} = C/E$). Then the amounts of both the desalted water (W) and the (lesser) net saleable power (E_2) produced by the dual-purpose plant, as well as its total expenses (C_2) are calculated. E_2 is lower than E, because of the energy needed for desalination in the dual-purpose plant, and C_2 is higher than C, because of the extra desalination expenses. The desalted water is then charged by these expenses and afterwards credited by the net salable power costs ($C_2 – E_2 \times C_{kWh}$). The cost of the desalted water is then calculated as:

$$C_{water} = (C_2 – E_2 \times C_{kWh}) / W$$

The cost of the saleable power C_{kWh} is the same as with the reference single-purpose power plant. If W, E/E_2, and C/C_2 are annual quantities expressed respectively in m^3, kWh and US \$, C_{water} is obtained in US \$ per m^3.

Another method – the exergy prorating method – is also discussed by the IAEA, but rejected as too complex to implement, even though, it seems that according to the exergy prorating method, all the advantages of size and resource sharing are allocated equally (and 'equivalently') between the power and the desalted water, while in the power credit method the water gets relatively more benefit.

Of course, the power credit method could be reversed to become the "water credit method," and all of the economies of scope between electricity and water could be allocated to electricity. This is a preferred method when the primary purpose of the facility is to produce water. Under the "water credit method," the amount of water produced by the reference single-purpose plant (W*) and total expenses incurred (C*) are calculated first, from which the cost per m^3 of water (C_W) is derived ($C_W = C^*/W^*$). Then the amounts of power (E_1) and water (W_1) produced by the dual-purpose plant, as well as its total expenses (C_1) are calculated. The power is then charged with these expenses and credited with the net salable water costs ($C_1 - W_1 \times C_W$). The cost of power becomes $C_{kWh} = (C_1 - W_1 \times C_W) / E$. This can be generalized to levelized costs (see below).

Choosing a cost between the costs estimated by these two methods is at the center of the literature on joint production. Because costs using these two methods differ, a cost range is determined; the literature discusses how to choose a cost within this range. However, most of the nuclear desalination literature follows the approach adopted in DEEP because for most nuclear power technologies, the desalination plant is much smaller than the nuclear generating plant. For example, Bogart and Schultz (2004, p. 8) state that "*It is important to compare the COW (Cost of Water) for a GT-MHR plant providing low-cost electricity ($0.029/kWh) to a reverse osmosis plant and the COW for a GT-MHR or H2-MHR plant providing low-cost electricity and 'free heat' to a MED (multi-effect distillation) plant*." "Free heat" implies the power credit method because water is not charged with the expenses of heat generation.

Under the power credit method, all of the savings from joint production are allocated to water, reducing the cost of water. Under the water credit method, all of the savings are allocated to electricity. While one method is as valid as the other is and neither method guarantees an economically efficient allocation, the present Guidelines suggest following the power credit method implemented in DEEP to evaluate the economics of joint production.

10.2.2 LUEC and LUPC for Joint Production Nuclear Energy Systems

Following the power credit method, the first step in determining the Levelized Unit Costs is to determine level 1 costs for the reference electric-only plant, i.e.,

A1 – Capitalized Pre-construction costs	(CPC)
A2 – Capitalized Direct Costs	(CDC)
A3 – Capitalized Indirect Cost	(CIC)
A4 – Capitalized Owner Cost	(COC)
A5 – Capitalized Supplementary Costs	(CSC)
A6 – Capitalized Financial Costs	(CFC)
A7 – Annualized Owner Cost	(AOC)
A8 – Annualized Supplementary Cost	(ASC)
A9 – Annualized Financial Cost	(AFC)

These costs and the net energy in each period are discounted to the present. The Levelized Unit Electricity Cost for the electricity-only plant, LUEC, is the ratio of total discounted cost C by total discounted energy E.

In a second step, level 1 costs are determined for the joint production facility. Many of these costs will be similar to those in the first step. However, there will be at least one other COA for the non-electric product. For example, in the case of desalination, these would be:

D1 – Capitalized Pre-construction costs	(CPC)
D2 – Capitalized Direct Costs	(CDC)
D3 – Capitalized Indirect Cost	(CIC)
D4 – Capitalized Owner Cost	(COC)
D5 – Capitalized Supplementary Costs`	(CSC)
D6 – Capitalized Financial Costs	(CFC)
D7 – Annualized Owner Cost	(AOC)
D8 – Annualized Supplementary Cost	(ASC)
D9 – Annualized Financial Cost	(AFC)

In those cases where the two systems share a component, e.g., in Account 25, the Heat Rejection System, A25 would be equal to the value for the electric-only plant and D25 would be equal to the remainder, i.e., only the extra costs are charged to the additional product. The resulting costs are discounted to the present. Their sum is equal to C_2. Also, net electricity for the joint production facility is discounted and summed to E_2 (less than E). Further, the net output of the other product in each period is discounted to the present and summed. If W represents the discounted sum of saleable non-electricity product (e.g., heat or hydrogen), the Levelized Unit Product Cost (LUPC) is:

$$LUPC = (C_2 – E_2 \text{ x } LUEC) / W$$

The LUEC and LUPC can then be used to determine whether the electric-only or joint production nuclear energy system is competitive in both the electricity market and with alternative sources of the non-electricity product. LUEC and LUPC will be simultaneously determined in the G4Econs software.

References

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11. FACTORY-PRODUCED MODULAR UNITS COMPARED TO LARGE SINGLE UNITS

To be added

ABBREVIATIONS, ACRONYMS, & EQUATION SYMBOLS

AACE	American Association of Cost Engineers
A/E	Architect/Engineering firm
AECL	Atomic Energy Limited of Canada
AFI	Allowance for indeterminates (type of contingency)
AFUDC	Allowance for Funds Used During Construction
AFCI	Advanced Fuel Cycle Initiative (DOE-NE program)
ALMR	Advanced liquid metal reactor
ALWR	Advanced light water reactor (III+)
BCC	Base construction cost
BOP	Balance of plant
BSDD	Building and structure design description
BWR	Boiling water reactor
CADD	Computer aided design and drafting
CEA	Comissariat à l'énergie atomique (French Atomic Energy Agency)
CER	Cost-estimating relationship
CF	Capacity factor
CM	Construction manager
CS	Carbon steel (refers to type of pipe)
COA	Code-of-account(s)
CONT	Contingency on base + owner's costs
CRD	Control Rod Drive
D&D	Decontamination and decommissioning
DCC	Direct construction cost
DEPLOY	Deployment costs, True FOAK costs allocated to each unit of plant.
DOE	Department of energy
EEDB	Energy economic data base
EDF	Électricité de France (French utility)
EIS	Environmental Impact Statement
EMWG	Economic modeling working group
EPC	Engineering, procurement and construction
EPRI	Electric Power Research Institute
EQM	Equipment manufacturer
ER	Environmental report
FBR	Fast breeder reactor
FC	Fuel Cycle
FCR	Fixed charge rate
FOAK	First-of-a-kind
GA	General Atomics
G&A	General and administrative (costs)
GDP	Gross domestic product
GIF	Generation IV International Forum
GFR	Gas-cooled fast reactor
GW	Gigawatt
GWe	Gigawatt electric
HEU	Highly enriched uranium
HM	Heavy metal

HTR	High-temperature reactor
HTGR	High temperature gas-cooled reactor
HVAC	Heating, ventilation and air conditioning
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
I&C	Instrumentation and control
IDC	Interest during construction
IFR	Integral fast reactor
INEEM	Integrated nuclear energy economic model
LFR	Lead-cooled fast reactor
LCC	Life cycle cost
LCIC	Levelized cost of capital component of LUEC
LCOM	Levelized O&M component of LUEC
LCFC	Levelized fuel cycle component of LUEC
LCDC	Levelized D&D component of LUEC
LEU	Low-enriched uranium
LFR	Lead-cooled fast reactor
LMR	Liquid metal reactor
LTA	Lead test assembly
LUEC	Levelized Unit of Electricity Cost
LUFC	Levelized Unit Fuel Cost
LUPC	Levelized Unit Product Cost (Hydrogen, etc)
LURC	Levelized Unit Reprocessing Cost
MHTGR	Modular high-temperature gas-cooled reactor
MOX	Mixed oxide fuel
MSR	Molten salt reactor
MTBF	Mean time between failures
MTTR	Mean time to repair
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt hour
MWth	Megawatt thermal
NATU	Natural uranium
NEA	Nuclear Energy Agency
NECDB	Nuclear energy cost data base
NEP	Nuclear energy plant
NI	Nuclear Island facilities
NNSA	National Nuclear Security Administration (USA)
NOAK	Nth of a kind
NSSS	Nuclear steam supply system
OC	Overnight cost
OECD	Organization for Economic Co-operation and Development
O&M	Operation and maintenance
ORNL	Oak Ridge National Laboratory
PBMR	Pebble bed modular reactor
P&IDs	Piping & Instrumentation Diagrams
PM/CM	Project Management/Construction Management
PNL	Pacific Northwest National Laboratory
POAK	Prototype-of-a-kind
PRA	Probabilistic risk assessment
PWR	Pressurized water reactor

Pu	Plutonium
Q/A	Quality assurance
Q/C	Quality control
r	Real cost of money
RCV	Reactor cooling-related vessels
R&D	Research and development
RD&D	Research, development, and demonstration
RM	Reactor manufacturer/vendor
RPV	Reactor pressure vessel
SAP	Safety Assessment Principles for Nuclear Plants (U.K.)
SAR	Safety analysis report
SCWR	Supercritical-water-cooled reactor
SDD	System Design Description
SEMER	Système d'évaluation et de modélisation économique des réacteurs
SFF	Sinking fund factor
SFR	Sodium-cooled fast reactor
SS	Stainless steel (pipe type)
SWU	Separative work unit
TCIC	Total capital investment cost
TOC	Total overnight cost
T/G	Turbine/Generator
T-H	Thermal hydraulic
U	Uranium
UOX	Uranium oxide fuel
USDOD	U.S. Department of Defense
USDOE	U.S. Department of Energy
USNRC	U.S. Nuclear Regulatory Commission
VHTR	Very-high-temperature reactor
WBS	Work Breakdown Structure

APPENDIX A. CONTINGENCY IN NUCLEAR ENERGY SYSTEM COST ESTIMATION

During the life of a nuclear energy system project, major cost estimates must be performed during each stage: (1) the initial R&D effort, (2) concept development, (3) concept confirmation, (4) preliminary design, (5) detail design, (6) construction, and (7) commercial operation. The project scope definition and the estimated cost basis improve with project specific detail. Progressively, the improvements in the pricing basis of the estimate reduce the risks and the associated contingency rates that are required to meet a desired confidence level.

The basis for establishing contingency rates to meet desired confidence levels should be consistent for each estimate through the life of the project. Each risk assessment should be based on the degree of confidence inherent in the components of the estimate. Initially, the pricing basis might include allowances that carry a high risk of cost overrun, but as the definition improves and more effort is made to improve the pricing basis with actual quotations, the precision of the estimated cost improves and lower contingency rates can meet the specified level of confidence.

The following are guidelines for contingency cost assessments at various stages of the project.

1. R&D concept development estimate or conceptual screening:

Initial cost estimates developed during the R&D phase of a nuclear energy system typically have limited design information and most effort is concentrated on defining the unique features of the reactor concept, fuel configuration, and the main heat cycle. The majority of the costs will be based on reference plant data with only the unique scope estimated with current price data. A simple model of project costs identifying the major cost drivers is sufficient, but the associated contingency rates could be as high as ± 50%, see Table A.1. (For examples of R&D concept development estimates, see *A Technology Roadmap for Generation IV Nuclear Energy Systems*, December 2002.)

2. Conceptual, feasibility, or simplified estimate:

With technology development, the project scope and costs becomes more defined. Lower contingency rates, e.g., ± 30%, yield the same confidence levels or probabilities of cost overrun.

3. Preliminary, detailed, or finalized estimate, or forecast:

Improvements in specifying the project scope and pricing basis reduce the overall project contingency rate. Typically at these stages of project definition, it is desirable to perform a more thorough risk assessment using simulation software, such as @RISK. The assessment is performed by constructing a detailed model of project costs, establishing functional relationships between costs and underlying uncertainties, and specifying a probability distribution for each uncertainty. The simulation software assigns random values to each uncertain variable and calculates the resultant project costs. With thousands of simulated costs, the probability of cost overrun can be calculated. Selecting the desired confidence level, or probability of cost overrun, provides a corresponding contingency level. (This same methodology can be used with the initial concept development estimates by constructing simple project cost models with a limited number of uncertain variables.) The process of assigning probability ranges to variables provides a means of identifying cost risks. In some cases, the extremely high and low values can be calculated for variables such as the composite labor cost as a function of overtime premiums or the percentage of apprentice labor.

4. Project forecasts:

Forecasts are performed during construction, after a project budget is established and progress is monitored against the budget. For major projects, such as a nuclear power plant or fuel fabrication facility construction, annual forecasts establish the current status and re-establish total project costs based on actual performance. Contingency assessments are performed as with finalized estimates, usually reducing the contingency levels. At the end of a project, the money at risk and corresponding contingency allowances are reduced to near zero.

Values for the appropriate contingency rate for each estimate type are presented in Table A.1. The table compares Project Stages and expected Accuracy Ranges recommended by the Association for the Advancement of Cost Engineering International (1997) and contingencies recommended in Electric Power Research Institute (1993).[1] (The association of AACEI definitions with EPRI definitions is approximate.) See Parsons (1999) for similar comparisons with American National Standards Institute, the UK Association of Cost Engineers, and the US Department of Energy, Office of Environmental Management.

Table A.1 Comparison of AAEC and EPRI Cost Estimate Categories

AAEC End Usage	AAEC Expected Accuracy Range	EPRI Designation	EPRI Suggested Contingency
Concept Screening	Low: -20% to –50% High: +30% to +100%	NA	NA
Feasibility Study	Low: -15% to –30% High: +20% to +50%	Simplified Estimate	30-50%
Authorization or Control	Low: -10% to –20% High: +10% to +30%	Preliminary Estimate	15-30%
Control or Bid/Tender	Low: -5% to –15% High: +5% to +20%	Detailed Estimate	10-20%
Check Estimate or Bid/Tender	Low: -3% to –10% High: +3% to +15%	Finalized Estimate	5-10%

Sources: American Associate of Cost Engineers International (1997) and EPRI (1993).

Lorance and Wendling (1999, p. 7) discuss expected accuracy ranges reproduced in Table A1: “The estimate meets the specified quality requirements if the expected accuracy ranges are achieved. This can be determined by selecting the values at the 10% and 90% points of the distribution.” This infers that 80% of the probability is contained between the outer bounds of the accuracy ranges, $\pm X\%$.

The cost estimator can determine an 80% confidence level by answering the following three questions: (1) What is the most likely final cost? (This is MODE.) (2) The final cost of the project will be *above* what value 90% of the time? (This is LOW.) (3) The final cost of the project will be *below* what value 90% of the time? (This is HIGH). Then –X% equals [(LOW–MODE)/MODE] and +X% equals [(HIGH–MODE)/MODE]. For example, let LOW = \$90, MODE = \$100, and HIGH = \$110, then $\pm X\% = \pm 10\%$.

To better understand confidence intervals and accuracy ranges, consider the normal ("bell-shaped") probability distribution.[2] This distribution can be completely described by its mean (the expected cost) and its standard deviation (a measure of the cost estimate uncertainty). The normal distribution is symmetric (it is equally likely that the final cost will be above or below the expected cost), so the mean equals the median (half the probability is above the median and half is below) and the mode (the most likely cost). (Section A2 considers the lognormal distribution in which the mean, median, and mode are not equal, and the expected accuracy ranges, as in Table A1, are not symmetric.) The standard deviation, σ, is the square root of the variance. The variance equals the average squared deviation of each observation from the mean. About 68% of the probability of a normal distribution is between plus and minus one standard deviation ($\pm\ \sigma$).

A.1 Contingency with a Normally-Distributed Cost Estimate

If the cost estimate is normally distributed, the standard deviation is $\sigma = X / Z$, where X is the level of accuracy and Z depends on the confidence level. For example, the level of accuracy for a "Preliminary Estimate" is about ±30%. If the cost estimator has an 80% confidence in this range of accuracy, Z = 1.28, i.e., 80% of the standard normal distribution is between $\pm\ 1.28 \cdot \sigma$. (For a given accuracy range, with a 50% confidence level, Z equals 0.67, and with a 90% confidence level, Z equals 1.65.) Therefore, $\sigma = (X / Z) = (30\% / 1.28) = 23.4\%$. If the cost estimator had a 90% level of confidence in the ±30% accuracy range, then $\sigma = (30\% / 1.65) = 18.2\%$, i.e., about two-thirds of the time the expected final cost would be ± 18.2% of the estimate of the most likely cost. As an example, consider the cost estimate in the following figure.

Figure A.1 A Cost Estimate with a Normal Distribution

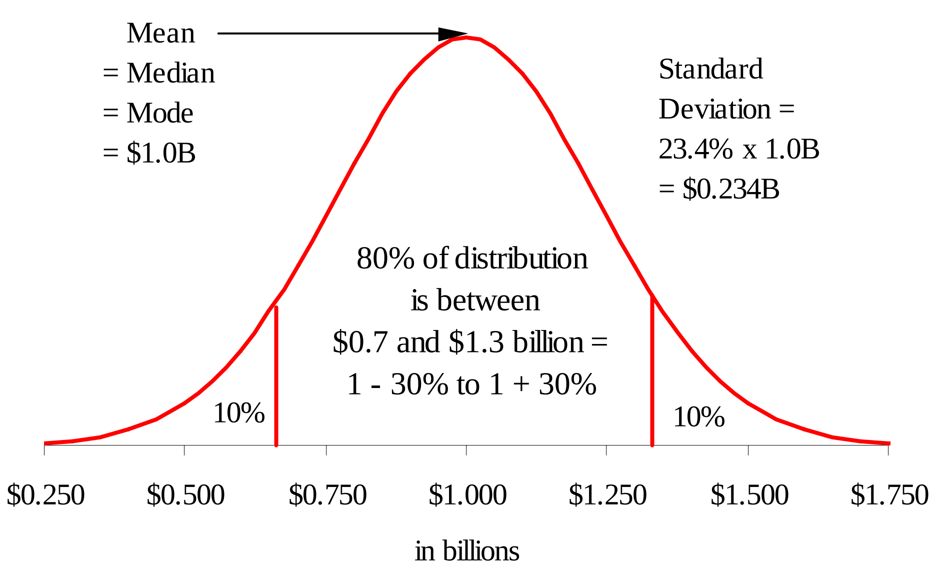

Figure A1 shows a normally distributed cost estimate with a mean, median, and mode of $1 billion and a standard deviation of $0.234 billion, or 23.4% of the expected cost. In this example, 10% of the distribution is below $0.700 (LOW) and 10% is above $1.300 billion (HIGH), yielding an 80% confidence level for an accuracy range of ±30%.

To approximate the underlying standard deviation of the cost estimate, the estimator can identify the upper and lower bounds (i.e., ± *X*%) that define an 80% confidence interval. How does this relate to the contingency estimate? In the AACEI and EPRI guidelines (see Table A1):

- Under the normal distribution, for a "Finalized Estimate" with X = ±10% and an 80% confidence, σ = (X/Z) = (10%/1.28) = 7.8%. Compare this with the AACEI-suggested contingency of 5% and the EPRI-suggested contingency of 5 to 10%.
- An accuracy range of ±20% for a "Detailed Estimate" yields σ = (20%/1.28) = 15.6%, compared with a suggested contingency by AACEI of 15% and by EPRI of 10 to 20%.
- An accuracy range of ±30% for a "Preliminary Estimate" yields σ = (30%/1.28) = 23.4%, compared with a suggested contingency by AACEI of 20% and by EPRI of 15 to 30%.

Therefore, the standard deviation of the cost estimate is approximately equal to the contingency suggested by AACEI and EPRI.[3]

A.2 Contingency with a Lognormal Cost Estimate

Many cost estimate accuracy ranges are non-symmetric, as shown in Table A1, where the low range is less (in absolute value) than the high range. This is because (1) final costs are usually higher than those estimated and (2) there is no probability that the final cost will ever be less than zero (which is a possibility with the normal distribution, however small the probability). Therefore, a non-symmetric distribution is more realistic for many cost estimates. One such probability distribution is the lognormal.[4]. Figure A2 presents three lognormal densities. Figure A3 presents the corresponding lognormal cumulative distributions.

In Figures A. 2 and A.3 all three estimates have the same mode, but have different medians, means, variances, and standard deviations, as shown in Table A2. As with all standard lognormal distributions, the mean is greater than the median, which is greater than the mode. Here, with the mode equal to 1.0 (billion dollars), variance equals [median · (median – 1)].[5] (The mode can be set to 1.0 by dividing the cost estimates by the mode.)

Figure A.2 Lognormal densities for three project stage estimates

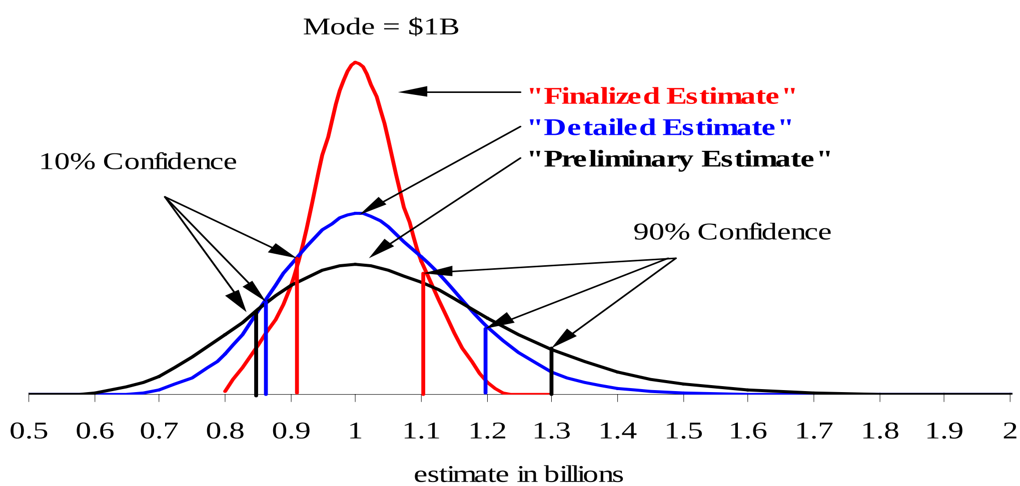

Figure A.3 Lognormal cumulative distributions for three project stage estimates

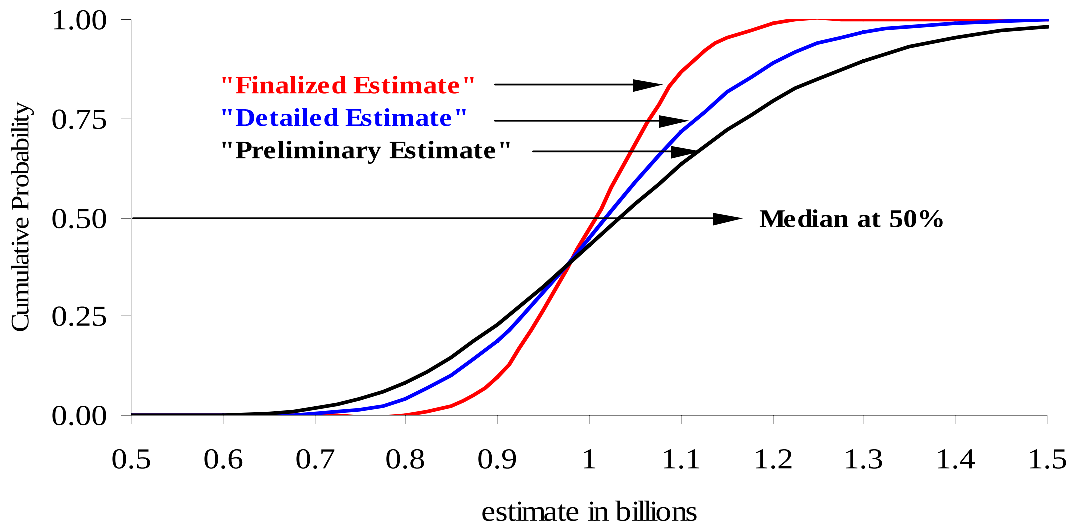

Table A.2 Medians, means and standard deviations for lognormal estimates

	Mode	Median	Mean	Variance	Standard Deviation	80% Confidence
Preliminary Estimate	1.000	1.033	1.049	3.4%	18.3%	-18% to +31%
Detailed Estimate	1.000	1.017	1.025	1.7%	13.1%	-14% to +20%
Finalized Estimate	1.000	1.005	1.008	0.5%	7.0%	-8% to +10%

Setting the contingency equal to the standard deviation, the contingency for a “Preliminary Estimate” with an 80% confidence interval between –18% and +31% would be 18.3%, which is less than the 20% contingency recommended by the AACEI, but within the range suggested by EPRI. The contingency for a “Detailed Estimate” is 13.1%, which is again less than the 15% suggested by the AACEI, but within the range suggested by EPRI. The contingency for a “Finalized Estimate” is 7%, which is greater that suggested by AACEI, but within the range suggested by EPRI. Therefore, cost estimates with lognormal distributions can also be assigned a contingency equal to the (lognormal) standard deviation. Further, as lognormal cost estimates become more precise, the distribution becomes more symmetric and the contingency approaches the values found for the symmetric normal distribution.

Finally, the accuracy ranges in Table A2 can be adjusted to the cost estimator’s confidence interval for a specific cost estimate following the parameters of the lognormal distribution. To determine these, the cost estimator needs to answer another question: The final cost of the project will be *above* (or *below*) what value 50% of the time? (This is MEDIAN.) The contingency is the square root of {(MEDIAN/MODE) · [(MEDIAN/MODE) – 1]}. Following the example above, let MODE = $100 and MEDIAN = $104, then contingency is $\{(\$104/\$100) \cdot [(\$104/\$100) - 1]\}^{1/2}$ = 20.4%, i.e., a contingency associated with a “Preliminary Estimate,” but with an 80% confidence interval of –20% to +35%. Cost estimators can calculate the standard deviation from the 80% confidence interval using a cumulative lognormal distribution, such as LOGNORMDIST in EXCEL, see Rothwell (2005). The median and standard deviation can be adjusted to the cost estimator’s 80% confidence interval and the accuracy range can be determined from the 10% and 90% cumulative probability.

A.3 Contingency in Levelized Capital Cost Estimation

This section proposes a method for determining the contingency associated with the estimation of the levelized capital cost (LCC):

$$\text{LCC} = [\ \text{CRF}(r, T) \cdot (\text{BCC} + \text{IDC} + \text{contingencies})\ ]\ /\ \Sigma\ [\ \text{E}\ (1 + \text{r})^{-\text{t}}] \tag{A1}$$

where CRF is the Capital Recovery Factor, equal to $\{ \text{r}\ (1 + \text{r})^{\text{T}} / [\ (1 + \text{r})^{\text{T}} - 1] \}$; BCC is the base construction cost; IDC is Interest During Construction; and E is the output per period (discounted to the present). Also, overnight cost (OC) is equal to BCC plus the contingency associated with the BCC estimate, as discussed in Sections A1 and A2. The Total Capital Investment Cost (TCIC) is BCC plus IDC plus all associated contingencies. This section provides a method of calculating a contingency associated with levelized capital costs based on the standard deviations of its underlying uncertainties. The contingency associated with BCC (σ_C) was discussed above. Therefore, we discuss the contingency associated with IDC and E.

A.3.1 Estimating Interest During Construction Contingency

Interest During Construction (IDC) is the cost of financing overnight cost (equal to BCC plus contingency) during the construction period. Abstracting from regulatory accounting, IDC is simply the difference between the value of construction expenditures at the start of the project and the value of these expenditures at the end of the project. It arises from the convention of calculating the value of the project at the time of construction completion. In fact, if all costs and revenues throughout the project's life were discounted to the beginning of construction, IDC would be zero.

To estimate IDC, consider capital expenditures discounted to the beginning of commercial operation (i.e., when revenues from the project begin):

$$\text{IDC} = \sum_{t = -LT}^{1} CX_t\ [\ (1 + r)^{-t} - 1\ ] \tag{A2}$$

where LT is the lead time (construction duration in months) of the project; CX_t are construction expenditures in month t; and r is the monthly cost of capital. (This formula assumes discounting from the beginning of each period. If the period were one year, this would lead to an overestimate if there are financing charges from the time of the expenditure. To correct for this, some formulas assume expenditure at mid-period. However, the overestimate of IDC approaches zero as the length of the period approaches zero, e.g., with monthly accounting the overestimate is small.)

Equation (A2) is a straightforward calculation if the construction expenditure distribution CX_t ($t = -LT, -LT+1, \ldots, 1$) and LT are known. However, at the beginning of the project both of these are uncertain. To focus on lead time uncertainty, assume that the CX_t have a uniform distribution, such that $CX_t = OC / LT$, where OC is overnight construction cost (base construction cost plus contingency) in real currency, i.e., abstracting from escalation during construction. Equation (A2) becomes (with the translation of subscripts):

$$idc = \sum_{t=1}^{lt} (OC / lt)\ [\ (1 + r)^{t} - 1\ ], \tag{A3a}$$

$$= (OC / lt)\ \{\ [\ \sum_{t=1}^{lt} (1 + r)^{t}\ ] - lt\ \}, \tag{A3b}$$

where idc is uncertain IDC and lt is uncertain lead time (with a mean of LT and a standard deviation of σ_{LT}). What is the standard deviation of idc? We can simplify Equation (A3b) by considering the series as a uniform, present worth factor:

$$\sum_{t=1}^{lt} (1+r)^{t} = [(1+r)^{lt} - 1] / r \qquad \text{(A4)}$$

Further, this exponential expression can be approximated with a second-order expansion:

$$(1+r)^{lt} \approx 1 + lt \cdot r + lt\,(lt-1)\,(r^{2}/2) + \ldots, \qquad \text{(A5)}$$

which can be substituted into Equation (A4) and simplified as

$$\sum_{t=1}^{lt} (1+r)^{t} \approx lt + lt\,(lt-1)\,(r/2). \qquad \text{(A6)}$$

Substituting this into Equation (A3b) and simplifying:

$$idc \cong OC\,(lt-1)\,(r/2) \cong lt \cdot OC \cdot (r/2), \qquad \text{(A7)}$$

The mean of idc is $LT \cdot OC \cdot (r/2)$ and the standard deviation is $\sigma_{LT} \cdot OC \cdot (r/2)$ (where LT is the mean lead time and σ_{LT} is the standard deviation of the lead time). The standard deviation of the IDC rate (%) is $\sigma_{LT} \cdot (r/2)$.

For example, with overnight costs of \$1160 million (M), a construction lead time of 48 months, a real discount rate of 0.833%/month (=10% per year), IDC equals \$232M. If the standard deviation of LT were 12 months, the standard deviation of IDC would be \$58M and the standard deviation of the IDC rate would be 5%. The Total Capital Investment Cost (TCIC = OC + IDC + contingencies) would be \$1160M + \$232M + \$58M = \$1450M. As the construction cost and schedule estimates become more precise, the standard deviation of the cost and lead time estimates should decrease, leading to a reduction in the associated contingencies.

Following the methodology in Section A1, contingency on IDC can be represented as $\sigma_{LT} \cdot OC \cdot (r/2)$, where the standard deviation of lead time can be determined by specifying an accuracy ($\pm X$%) with an 80% confidence interval for the estimate of lead time. This accuracy may be greater than or less than the accuracy of the base construction cost estimate. It should correspond to the level of detail of the construction schedule estimate. (This assumes that σ_C and σ_{LT} are not correlated.)

A 3. 2 Estimating Capacity Factor Contingency

Next, E is annual output (e.g., in megawatt-hours), can be defined as

$$E = CF \cdot \mathrm{MAX} \cdot \mathrm{Y}, \qquad \text{(A8)}$$

where (1) the capacity factor, CF, is the percent of maximum output generated in a year, (2) MAX is the plant's annual *net* maximum dependable output, and (3) Y is the total hours in a year. (MAX and Y are constants.) For example, a power plant with a net maximum dependable capacity of 1350 MW (equivalent to a gross capacity of 1400 MW) operating at a 90% capacity factor for 8,760 hours per year generates about 10,600,000 MWh for sale per year. The CF can be decomposed to facilitate an analysis of its uncertainty:

$$CF \quad = \quad [\, E /(\mathrm{MAX} \cdot H\,)] \cdot (H\, /\, \mathrm{Y}) \;=\; CU \cdot SF\,, \qquad \text{(A9)}$$

where H is the total *generating* hours per a year. The first term, $[E\ /\ (\mathrm{MAX}\ \cdot\ H\ )]$, is the capacity utilization rate, CU, a measure of how close the plant is to potential output when it is running. The second term, $(H\ /\ \mathrm{Y})$, is the service factor, SF, the percentage of the time the plant is running. For example, if the CU rate is 95% and the SF is 95%, then the capacity factor would be about 90%. On these rates for U.S. nuclear power plants, see Rothwell (2000).

Although there can be uncertainty associated with CU (and CU can be estimated at less than 100%), the uncertainty in CF is usually dominated by uncertainty in the Service Factor, i.e., how much time a facility will be down for repair and maintenance. Assuming that the expected capacity factor is 90% (= SF and CU = 100%), the expected number of days of outage would be 36.5 days per year. Assuming an accuracy range of ±30% with a confidence of 80%, expected days of outage would be between 25.5 and 47.5 days per year, i.e., the capacity factor would range from 93% to 87% with a standard deviation (σ_{SF}) of 23% for the days of outage. Following the same methodology as above, the standard deviation on the Capacity Factor, σ_{CF}, would be $\sigma_{SF} \cdot (1 - SF) =$ 23% · (1 – 90%) = 23% · 10% = 2.3% and the contingency-adjusted Capacity Factor would be 87.7% = $\mathrm{CU} \cdot (\, SF - \sigma_{CF}\,)$, treating the contingency as a penalty. On the other hand, an accuracy range of ±20% with a confidence of 80% would imply a standard deviation of 16% or σ_{CF} = 1.6% and a contingency-adjusted capacity factor of 88.4%.

Contingency on CF can be set equal to $-\sigma_{CF}$, where the standard deviation of capacity factor can be determined by estimating the standard deviation of scheduled outage days from specifying an accuracy range (± X%) with an 80% confidence interval. This accuracy may be greater than or less than the accuracy of the base construction cost or construction schedule estimate. It should correspond with the level of detail of the operations and maintenance schedule estimate.

A.3.3 Estimating Levelized Capital Cost Contingency

The standard deviation of estimates for cost, lead time, and capacity factor give reasonable values for each contingency. These standard deviations can be derived from the estimator's 80% confidence interval around the most-likely values. This should lead to contingencies that are approximately equal to those suggested by guidelines such as AACEI (1997) and EPRI (1993).

Taking these contingencies into account leads to a contingency-adjusted value for the Levelized Capital Cost:

$$\mathrm{LCC} \;=\; \mathrm{CFR}(r,\, T) \cdot \{\, (\mathrm{BCC}{+}\sigma_{\mathrm{C}}) \cdot [1 + (LT + \sigma_{LT})\,(r/2)]\, \}/\, [(CF - \sigma_{CF}\,)\, (\mathrm{MAX} \cdot \mathrm{Y})], \qquad \text{(A11)}$$

where LCC is expressed in \$ per unit of output; CFR, r, SF, and σ_{CF} are expressed as percentages (e.g., r = 10%); T is expressed in years; BCC and σ_{C} are expressed in real dollars; LT and σ_{LT} are expressed in months; MAX is expressed in MW; and Y is hours per year.

For example, if CFR = 10.23%, BCC = \$1,000M, σ_{C} = \$160M, LT = 48 months, σ_{LT} = 12 months, CF = 90%, σ_{CF} = 2.3%, MAX = 1000MW, and Y = 8,760 hours; then LCC = \$17.37/MWh. Ignoring Capacity Factor contingency reduces LCC to \$16.93/MWh; ignoring Capacity Factor and IDC contingencies reduces LCC to \$16.56/MWh; and ignoring all contingencies reduces LCC to \$14.27/MWh. In this example, base construction cost contingency has the greatest impact on LCC. Therefore, the greatest attention should be paid to reducing uncertainty in the base construction cost estimate (this should also reduce uncertainty in the construction schedule and in the maintenance and repair schedule).

Endnotes

1. EPRI (1993) is the last publicly available version of the *Technology Assessment Guide*. Later versions are proprietary, but use the same definitions and Suggested Contingencies as in Table A1.

2. The normal density function is $N(x) = (2\pi\sigma^2)^{-½}$ A $\exp\{-(1/2)$ A $(x-\mu)^2/\sigma^2\}$, μ is the mean and σ is the standard deviation. See Palisade (1996, p. 235).

3. Lorance and Wendling (1999, p. 7) state "We are most familiar with and strongly support assigning contingency such that the base estimate plus contingency equals the 50/50 point (median) of the cumulative distribution." In their Monte Carlo example, "note that at the 50/50 point is a 16.2% contingency." (p. 6). The standard deviation of their cost estimate is 16.6% = (14,170/85,156), i.e., their example is consistent with the conclusion reached here.

4. The lognormal density is $LN(x) = x^{-1}(2\pi\sigma^2)^{-½}$ A$\exp\{-(1/2)$A$(\ln x-\mu)^2/\sigma^2\}$, where μ equals the natural log of the median and σ^2 equals the natural log of the median minus the natural log of the mode. The mean is $\exp\{\mu + (\sigma^2/2)\}$. The variance is $\exp\{2\mu - \sigma^2\}[\exp\{\sigma^2\} - 1]$ and the standard deviation equals the square root of the variance. See Palisade (1996, p. 233) and Johnson, Kotz, and Balkarishnan (1995). The LOGNORMDIST function in EXCEL (e.g., in OFFICE97, equal to LOGNORM in Palisade, 1996, p. 232) can be used to calculate the lognormal probability cumulative distribution, as in Figures 3 and 4. However, in LOGNORMDIST the "mean" is the natural logarithm of the median in Table A2 and the "standard deviation" is as in Table A2.

5. With the mode equal to 1.0, both μ and σ^2 are equal to the natural log of the median and the variance equals $\exp\{2\ln(\text{median}) - \ln(\text{median})\}[\exp\{\ln(\text{median})\}-1] = [\text{median}\cdot(\text{median}-1)]$.

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APPENDIX B. A COSTING PROCESS FOR ADVANCED REACTOR DESIGNS

With the start of Generation IV design efforts there is opportunity for cost modeling to be directly integrated into the design process. The *Cost Estimating Guidelines* can become integrated into the design process. The resulting "Costing Process" is the use of an integrated model that unites engineering aspects (such as thermal hydraulics, nuclear core physics, heat transfer, process control, etc.) with economics by using cost scaling algorithms for various subsystems. (The EEDB report with PWR cost scaling relationships has examples of such algorithms for reactor systems.) As an example, a costing process used by AECL for advanced reactor design has the following sequential elements and is based on a reference perturbation technique:

(a) Establish targets for cost, product streams, performance, safety, O&M, etc.
(b) Establish a reference (built or designed) plant cost
(c) Define the changes from that reference design for a given concept
(d) Cost-estimate the changes
(e) Iterate back to (c) when needed vis-a-vis the targets in (a)
(f) Finalize the system concept and outline the RD&D needs
(g) Conduct engineering and cost feasibility study for the concept, including uncertainty and risk
(h) Iterate back to (c) if needed: establish any reference changes
(i) Finalize the design concept and its FOAK cost using actual bids/quotes as needed
(j) Define confirmatory RD&D cost and schedule, including uncertainty and risk
(k) Establish Preliminary Engineering Design
(l) Cost estimate the design including NOAK estimates, including uncertainty and risk
(m) Cost estimate all product streams per assumed market(s)
(n) Iterate to (i) as needed
(o) Conduct Engineering Design Program for FOAK and/or prototype, complete RD&D
(p) Undertake independent review of costs with customer(s)
(q) Establish Owners Costs and define business model
(r) Finalize cost(s) for all product streams (e.g., hydrogen, electricity, process heat, etc.)
(s) Establish risk, financing, contract, and project model for build schedule
(t) Iterate to (q) as needed
(u) Prepare formal cost estimates to bid spec(s) using guidelines and/or conventional national practice

APPENDIX C. SITE-RELATED ENGINEERING AND MANAGEMENT TASKS

- Prepare site-related engineering specifications and drawings (layouts, design, manufacturing, installation, and interface control drawings).
- Identify and re-tab non-site drawings (design, manufacturing, installation, and interface control drawings), technical documents, specifications, and manuals to show applicability to the Target Plant.
- Update and maintain technical work packages.
- Provide support at vendor's plant to witness factory acceptance testing.
- Support the constructor during plant construction and acceptance testing.
- Provide support to the Materials Review Board
- Provide support as specifically requested to SAR (including emergency response) to show that the plant is identical in design.
- Support vendor bid evaluations and negotiations as requested by Procurement for releases of previously bid and committed awards.
- Support the Constructor in the resolution of any field problems.
- Prepare site-specific licensing documents, such as ER and SAR.
- Repeat plant planning and scheduling and administrative, quality assurance, procurement, and industrial and public relations activities.
- Provide modularization schedule/sequencing plan.
- Provide engineering necessary to excavate and lay out the site for construction. This includes excavation drawings; de-watering calculations and analyses; and design and layout of access roads, parking lots, utilities, etc.
- Provide project management services associated with the above tasks.

APPENDIX D. SITING PARAMETERS

GENERAL

Soil and subsurface conditions are such that no unusual problems are associated with soil-bearing capacity or rock removal, major cut and fill operations, and de-watering.

Assumed site access will not rely on barge delivery of large pre-assemblies or modules. All deliveries will be possible by rail or road transport without requiring unreasonable size or weight capacity.

Cooling water make-up for on-site cooling towers will be available at site boundary.

Construction access, construction electricity, water, telephone, police service, ambulance service, and other support services are available in the proximity of the site.

The primary purpose of defining regions is intended to support comparison of different reactor systems at the same site, rather than the same reactor system at different sites.

D.1 North America

D.1.1 United States

The 1993 ORNL Guidelines (Delene and Hudson, 1993)defined a reference site in the Northern US along with the relevant meteorological, water, seismic, soil, atmospheric dispersion, and infrastructure data. This data is no longer relevant due to the fact that under DOE partial sponsorship, utilities in the U.S. have now identified three actual existing plant sites for analysis. Unfortunately at this time the data is not available. The only siting parameter available in the *ALWR Requirements Document, Volume 1*, is the 0.3g seismic acceleration. The full listing of site parameters is in one of the proprietary volumes. No alternative sites have been found on IAEA or NEA web sites.

It is suggested that the EMWG limit its assumptions on siting for U.S. sites to 0.3 g (i.e., 294 $cm.sec^{-2}$) seismic and the use of cooling towers for the ultimate heat sink. Most other parameters will be second order effects, especially for the conceptual design stage.

D.1.2 Canada

It is suggested that the EMWG limit its assumptions on siting for Canadian sites to 0.3 g (i.e., 294 $cm.sec^{-2}$) seismic and optional use of cooling towers for the ultimate heat sink. Most other parameters will be second order effects, especially for the conceptual design stage.

D.2 Asia

D.2.1 Japan

In Japan, the main steps for seismic design are as follows (Nuclear safety Commission of Japan, 1981).

At first, the classification of the facilities is carried out. For class As and class A facilities, the maximum design earthquake ground motion S1 and/or extreme design earthquake ground motion S2 are to be evaluated. Reference for S1 is the recorded (historical) earthquake, and that for S2 is the seismological review.

Design seismic force, depending on the site location, is decided by the S1 or S2 earthquake ground motion and the static seismic force. The maximum S1, S2 design earthquakes for the operating power stations in Japan are 450 gal and 600 gal (1 gal = 1 $cm.sec^{-2}$), respectively.

D.3 Europe

D.3.1 France

Proper assumptions for European sites will be added later.

D.3.2 United Kingdom

Requirement for site selection and qualifications are provided by HM Nuclear Installations Inspectorate – Safety Assessment Principles (SAP) for Nuclear Plants at their web site, http://www.hse.gov.uk/nuclear/saps.htm

References

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APPENDIX E. ESTIMATING FOAK TO NOAK CAPITAL COSTS

Design teams will be estimating Base Construction Costs (BCC) as First-of-a-Kind (FOAK) costs and Nth-of-a-Kind (NOAK) costs. (BCC are the sum of Direct Costs, DC, and Indirect Costs, IC.) This appendix discusses the translation of FOAK to NOAK costs and vice versa.

To facilitate consistency in the estimates produced by each design team, the following assumptions define the basis for calculation of the cost adjustment factors for a nominal plant size of 1,000 MWe:

Definition of FOAK plant

- First commercial plant built with estimated equipment, materials and labor productivity based on current or recent nuclear plant experience.
- Past US nuclear plants are regarded as "Replica Plant" experience. Somewhat better than true FOAK plants.
- Marketing strategy may consider pricing of all plants, from the first commercial plant to the plant prior to NOAK plant, and to be levelized for recovery of common development, design, certification, tooling, fabrication plant recovery and other common non-recurring costs.
- Deployment costs or true FOAK, non-recurring cost components are to be identified and separately priced.

Definition of NOAK plant

Identical plant supplied and built by same vendors and contractors as the FOAK plant with only the site specific scope adopted for the NOAK plant site needs.

- NOAK costs are achieved for the next plant after 8 gigawatt (GWe) of capacity has been constructed of a particular nuclear energy system.
- Costs decline with each doubling of experience.
- Fleet size is 32 GWe for considerations of sizing support facilities such as fuel fabrication or reprocessing.
- The series of plants from FOAK through NOAK plant are assumed to be competitively bid for a comprehensive award and release of individual plants on an optimum schedule for the selected vendors and contractors.
- Project execution (up through the NOAK plant) is based on a single large A/E organization providing project management, engineering, procurement and construction (EPC) services. Construction will be performed by direct hire labor with subcontractors for specialty work.

Cost factors between FOAK and NOAK plants

- ***Construction schedule*** for the first commercial plant is most likely performed on a regular 5 x 8's work week schedule. Subsequent plants may incorporate accelerated construction schedules optimized to reduce plant costs inclusive of cost of money. Alternative construction work week schedules such as rolling 4 x 10's can improve productivity by reducing manpower densities, improving material flow and work access. Alternative workweek schedules may incur premium labor costs and still produce an overall cost benefit, especially when cost of money is included in the assessment.
- ***Construction labor*** learning effect has been demonstrated on many construction projects. Learning cost factors of 0.90 for every doubling of construction labor is recommended, and has been utilized in other previous cost studies. "Construction labor learning effect" includes all

benefits derived from construction of a standardized plant, including – 100% design prior to start of construction, computer models detailed for all structural commodities, services and utilities; Detail work schedules, optimized sequence of construction derived from previously constructed plants, detail work packages with pre-staged materials, equipment, tools and supplies, reduction and elimination of construction re-work and work-arounds; Experienced supervision and site engineering staff; Availability of all equipment and materials on an as-needed, just-in-time delivery basis. The resultant benefit is a reduction in the total craft hours required to perform the same amount of work.

- Learning effect is also reflected in pricing of shop fabricated equipment, especially the non-standard equipment that is typical for nuclear power plants. A learning cost factor of 0.94 for every doubling of ***process equipment*** costs is recommended.
- The marketing strategy of awarding multiple plant orders supports procurement of large quantity of ***bulk materials*** with discounted pricing. Other cost studies have utilized a 10% discount for NOAK plant orders.
- The learning effect is also applicable to ***field indirect costs*** that will experience benefits of repeat construction activities that are pre-planned at detail daily work plans and pre-staged work packages. NOAK plant construction indirect costs will experience a reduction relative to the direct labor costs which are also affected by their own learning factors. A learning cost factor of 0.97 for every doubling of plant construction costs is recommended.
- Operations and Maintenance are a major component of the LEUC and historically have demonstrated reductions in costs attributed to improvements in the information technology and owners operations and maintenance programs. Proponents are to provide supporting data for any learning factors applicable to O&M costs of the NOAK plant and beyond.

There are two cost drivers: (1) the recovery of deployment costs over the transitional units; and (2) the decline in BCC from learning-by-doing (and other cost saving effects, such as, scale economies in commodity purchasing) during the construction of transitional units.

To quote the Guidelines, "Deployment costs: Costs of developing a standard design and licensing it. These are considered part of non-recurring FOAK costs and are distinct from R & D costs." These are "True FOAK Costs" in Figure 1.1.

Design and certification costs, DEPLOY, are assumed to be equally distributed over 8 GWe of capacity. For example, if each unit were 1 000 MWe, then all deployment costs would be recovered with the first eight units, such that the 9th unit would be free of deployment costs. On the other hand, if each unit were 333 MWe, these costs would be distributed over the first 24 units, so that the 25th unit would be free of deployment costs. Deployment cost per unit is:

$$DEPLOY_{UNIT} = (DEPLOY \times SIZE) / (8 \text{ GWe}),$$

where DEPLOY is in millions of dollars per unit and SIZE is the unit size in gigawatts. For example, if design costs were \$200M, certification costs were \$200M, and these costs are recovered over the construction of the 8 first 1,000 MW units, then $DEPLOY_{UNIT}$ would be[(200+200) x 1.00] / 8 = 50, or \$50M/unit.

The decline in BCC from FOAK to NOAK units can be modeled as described below. To quote the Guidelines, "Learning experience can be included for NOAK plant based on learning factors to be developed by each team. Guideline factors for each doubling of construction experience are 0.94 for equipment costs, 0.90 for construction labor, a 10% reduction in material costs for multi plant orders and 0.97 for field indirect costs." For an approximation, when account costs are not detailed to equipment, labor, and bulk material, cost estimators can assume that direct construction costs (Accounts 1-2) decline at the rate equivalent to, i.e., 0.94. Under these assumptions:

$$BCC_i = DEPLOY_{UNIT} + IC + (DC \cdot GW_i^{\,\gamma}) \qquad \text{for } GW_i < 8 \text{ GW}$$
$$BCC_i = CSC + (DCC \times 8^{\gamma}) \qquad \text{for } GW_i \geq 8 \text{ GW}$$

where γ represents the "learning elasticity" and GW_i is the cumulative capacity. (See IAEA, *International Project on Innovative Nuclear Reactors and Fuel Cycles, INPRO*, May 2003, p. 46). Learning elasticity is assumed such that cost declines by 6% with each doubling, i.e., that $\gamma = \log 0.94/\log 2 = -0.089$. For example, for a 1,000 MW plant and with FOAK DCC_1 = \$1,000M,
DCC_2 = \$940M, DCC_3 = \$912M, DCC_4 = \$884M, DCC_5 = \$870M, DCC_8 = \$831M,
and $DCC_{NOAK(9th)}$ = \$824M

With deployment costs of \$57M and Indirect Costs of \$400M, FOAK BCC_1 = \$1,457M,
BCC_2 = \$1,369M, BCC_3 = \$1,329M, BCC_4 = \$1,288M, BCC_8 = \$1,211M and $BCC_{NOAK(9th)}$ = \$1,200M.

The indirect costs in the above example would be separately evaluated for NOAK values based on the learning factors applicable to indirect costs

Appendix F. GIF CODE OF ACCOUNTS DICTIONARY

F.1 GIF Code of Account Structure and Dictionary for Capital Cost Estimates

The investment costs for a complete nuclear energy system, or its parts, include the costs of engineering, construction, commissioning, and test run before commercial operation. The base costs include costs associated with equipment, structures, installation, and materials (these are direct costs), as well as costs associated with field indirect, design services, construction supervision and PM/CM services (these are indirect costs). In addition to the base costs, there are supplementary costs (such as initial core and spare part costs), financial costs (such as Interest During Construction), owner's costs (including the owner's services costs), and contingency. The Total Capital Investment Cost (TCIC) is the cost of building the plant and bringing it to commercial operation.

The GIF Code of Accounts (COA) is a numeric system designed to provide cost information for any component of a project, from design, layout, and procurement of equipment, to the final installation. At the two-digit level, it can be applied to either top-down or bottom-up cost estimates. At the two-digit level, the subsystem category names should be applicable regardless of the nuclear system or technology described. At the three-digit level, commonality of account descriptions between reactor energy systems and fuel processing and reprocessing systems begins to break down. At the three and four digit levels, a bottom-up estimate is usually required. Chapter 5 presents definitions at the three-digit level for use in bottom-up estimating. Although the GIF COA is primarily a system of cost accounts, as a project matures, it can be used for other purposes, such as filing, drawing and document control, and numbering and coding of equipment.

The GIF Guideline's COA is structured as follows:

10:	Capitalized Pre-Construction Costs	(CPC)
+20:	Capitalized Direct Construction Costs	(CDC)
=	DIRECT CONSTRUCTION COSTS	(DCC)
+31-34:	Capitalized Field Indirect Costs	(FIC)
=	TOTAL FIELD COSTS	(TFC)
+35-39:	Capitalized Field Management Costs	(FMC)
=	BASE CONSTRUCTION COST	(BCC)
+40:	Capitalized Owner Costs	(COC)
+50:	Capitalized Supplementary Costs	(CSC)
=	OVERNIGHT CONSTRUCTION COST	(OCC)
+60:	Capitalized Financial Costs	(CFC)
=	TOTAL CAPITAL INVESTMENT COST	(TCIC)

The GIF COA structure includes prefixes and suffixes to the basic code for separation and summarization of costs at various levels. The structure and details are described in the following sections: Section 2, Structure; Section 3, Direct Costs; Section 4, Indirect Costs; Section 5, Annualized Costs; and Section 6, Non-Reactor Codes.

F.2 GIF COA Structure and Dictionary for Capital Cost Estimates

The full COA structure consists of components for identification and segregation of costs by

1) **Unit,**
2) **Plant,**
3) **System/Facility, and**
4) **Commodity.**

For example, "1A212.1" refers to the cost of concrete for "Reactor Island Civil Structures" for the first reactor at a site. "1A212" refers to the cost of "Reactor Island Civil Structures" for the first reactor. "1A21" refers to the cost of all "Structures and Improvements" for the first reactor. "1A2" refers to a plant equipment. ll Capitalized Direct Costs for the first reactor. Alternatively, "1A212.1" refers to the cost of concrete for "Reactor Building Civil Structures" for the first reactor at a site. "1A212" refers to the cost of "Reactor Building Civil Structures" for the first reactor. "1A21" refers to the cost of all "Structures and Improvements" for the first reactor. "1A2" refers to plant equipment for the first reactor. lA refers to all costs for the first reactor.

The first component is the **Unit** prefix, representing the unit (or module) number of a multiple unit plant.

1 – Unit or module one
2 – Unit or module two
3 – Unit or module three
4 – Unit or module four
5 – Unit or module five
6 – Unit or module six
7 – Unit or module seven
8 – Unit or module eight
9 – Common to all modules or units
0 – Total plant (all units and common)

The second component is **Plant** prefix: Alpha character representing the type of plant, such as

A – Electric Power Plant
B – Fuel Fabrication Plant
C – Fuel Reprocessing Plant
D – Desalination Plant
H – Hydrogen Generation Plant
W – Waste Repository
X – Other Process Plant

Where appropriate, electricity production will be considered as a primary product with allocation of common costs. Only product specific costs for other product equipment and systems will be coded to secondary product costs, such as Desalination or Hydrogen production plant equipment. This will require account 23 to be coded as 1A23 for Turbine-Generator and 1D23 for Desalination Plant Equipment.

The third component is the **System/Facility** identifier consisting of two digits (derived from the EEDB and IAEA Codes of Accounts) representing the major systems of the plant:

The first digit groups costs by type:

1 – Capitalized Pre-construction costs	CPC
2 – Capitalized Direct Costs	CDC
3 – Capitalized Indirect Support services	CIC
4 – Capitalized Owner costs	COC
5 – Capitalized Supplementary Costs	CSC
6 – Capitalized Financial Costs	CFC
7 – Annualized Owner Cost	AOC
8 – Annualized Supplementary Cost	ASC
9 – Annualized Financial Cost	AFC

The second digit identifies costs summarized by the first digit:

1 – Capitalized Pre-construction Costs (CPC)
11 – Land and Land Rights
12 – Site Permits
13 – Plant Licensing
14 – Plant Permits
15 – Plant Studies
16 – Plant Reports
17 – Other Pre-construction Costs
18 – Other Pre-construction Costs
19 – Contingency on Pre-construction Costs

2 – Capitalized Direct Costs (CDC)
21 – Structures and Improvements
22 – Reactor Equipment
23 – Turbine-Generator Equipment
24 – Electrical Equipment
25 – Heat Rejection System
26 – Miscellaneous Equipment
27 – Special Materials
28 – Simulator
29 – Contingency – Direct Costs

Accounts 1 + 2 = DIRECT CONSTRUCTION COSTS (DCC)

3 – Capitalized Indirect services Cost (CIC)
31-34 Field Indirect Cost (FIC)
31 – Field Indirect Costs
32 – Construction Supervision
33 – Commissioning and Start-up Costs
34 – Demonstration Test Run

Accounts 10-34 = Total Field Cost (TFC)

35-39 Field Management Cost (FMC)
35 – Design Services Offsite

36 – PM/CM Services Offsite
37 – Design Services Onsite
38 – PM/CM Services Onsite
39 – Contingency on Support Services

Accounts 1 + 2 + 3 = BASE CONSTRUCTION COST (BCC)

4 – Capitalized Owner Cost (COC)
41 – Staff Recruitment and Training
42 – Staff Housing
43 – Staff Salary Related Costs
44 – Other Owner Costs
49 – Contingency on Owner Costs

5 – Capitalized Supplementary Costs (CSC)
51 – Shipping and Transportation Costs
52 – Spare Parts
53 – Taxes
54 – Insurance
55 – Initial Fuel Core Load
58 – Decommissioning Costs
59 – Contingency Supplementary Costs

Accounts 1 + 2 +3 + 4 + 5 = OVERNIGHT CONSTRUCTION COST (OCC)

Accounts 1 + 2 +3 + 4 + 5 = OVERNIGHT CONSTRUCTION COST (OCC)

6 – Capitalized Financial Costs (CFC)
61 – Escalation
62 – Fees
63 – Interest During Construction
69 – Contingency – Financial Costs

Accounts 1 + 2 + 3 + 4 + 5 + 6 = TOTAL CAPITAL INVESTMENT COST (TCIC)

7 – Annualized Owner Cost (AOC)
71 – Operations and Maintenance Staff
72 – Management Staff
73 – Salary Related Costs
74 – Operating Chemicals and Lubricants
75 – Spare Parts
76 – Utilities, Supplies, Consumables
77 – Capital Plant Upgrades
78 – Taxes and Insurance
79 – Contingency Annualized Owner Costs

8 – Annualized Supplementary Cost (ASC)
81 – Refueling operations
84 – Nuclear Fuel
86 – Fuel reprocessing Charges
89 – Contingency Annualized Supplementary Costs

9 – Annualized Financial Costs (AFC)
91 – Escalation
92 – Fees
93 – Cost of Money
99 – Contingency Annualized Financial Costs

The third digit (and fourth digit) provide(s) the lowest level of GIF code for comparisons between plants and development of reference plant costs by top-down techniques. The third digits for Electric Power Plant are discussed in the sections below.

The fourth component is a **Commodity** identifier consisting of numeric digits, following a decimal point separator, located after the System/Facility codes. Detailed, bottom-up estimates would be performed by (1) quantifying the commodities to individual size level, (2) applying unit hour and unit material cost rates to develop the detail commodity cost, and (3) summarized to the third digit of the GIF code. (Commodity detail codes provide further separation for structural component, size or detail type of commodity.)

Detailed commodity accounts consist of the following categories and commodities:

1- Concrete Category: Commodities – (11) Formwork, (12) decking, (13) rebar, (14) embedded metals, (15) structural concrete, (16) fill concrete, (17) pre-cast concrete, and (18) concrete structural modules.

2 – Structural Category: Commodities – (21) Structural steel, (22) miscellaneous steel, (23) liners, (24) fabricated commodities, (25) architectural, (26) earthwork, (27) piles, and (28) site improvements.

3 – Nuclear Steam Supply System Category: Commodities – (31) Reactor vessel, (32) reactor internals, (33) CRD components, (34) install internals, (35) install components, (36) installation support activities.

4 – Mechanical Equipment Category: Commodities – (41) T/G equipment, (42) condenser, (43) rotating equipment, (44) heat exchangers, (45) tanks and vessels, (46) water treatment, (47) radioactive waste, (48) miscellaneous equipment, and (49) HVAC system components.

5 – Piping Category: Commodities – (51) Large shop fabricated pipe, (54) special pipe, (55) small pipe, (56) vendor pipe, (58) valves, and (59) hangers and piping miscellaneous operations.

6 – Instrumentation Category: Commodities - Control room equipment, local control panels, field mounted instruments, instrument supports, instrumentation tubing, packaged control systems, control and relief valves, calibration testing.

7 – Electrical Equipment Category: Commodities - Switchgear, transformers, bus duct, D.C. equipment, motor control centers, other electrical equipment, miscellaneous electrical equipment, switchyard equipment.

8 – Electrical Bulks Category: Commodities - Cable tray, scheduled conduit, other conduit, scheduled wire and cable, scheduled connections, other wire and cable.

9 – Specialty Materials and Equipment Category: Commodities - Plant specific materials and equipment unique to other plants such as fuel fabrication, fuel reprocessing, hydrogen generation, or desalination.

F.3 Direct Costs

In the GIF COA account system structure (derived from IAEA and EEDB), the "twenty-X" series is reserved for the direct costs of construction, i.e., the on-site labor, materials, and equipment. The original IAEA account system does not include labor in the 2X series of accounts. It included labor-hours in an indirect account. The EMWG has decided for the GIF Code of Account, to put labor in the direct costs to obtain greater understanding and integrity of subsystem costs across countries. The direct labor component includes the labor costs of "hands-on" craft (up to supervisor) workers. The category does not include indirect workers (Non Manual labor) such as superintendents, field engineers, A/E, or reactor-vendor home office staff, or construction services staff. These are included in the "Support Services" Accounts 3X. Subcontract cost and labor should be included in the 2X series if it is for the direct scope of work. Craft labor providing common support of construction such as temporary lighting, warehousing, clean up, etc, is included in account 31 – Field Indirect Costs.

At the two digit level (COA "2X") this GIF (IAEA/EEDB) format should fit most nuclear energy system technologies and be useable for top-down estimates. At the three digit level (COA "2XX") some of the subsystems may only fit a non-generic GIF plant, i.e., they will only apply for a specific reactor or fuel cycle technology. The three digit categories below (beneath each two-digit header) give the user an indication of where the more detailed cost items should be grouped. An attempt has been made to keep the three-digit definitions as generic as possible, although most are based on the PWR COA dictionary in the original EEDB documents (ORNL, 1988). Engineering judgment can be used to assign non-PWR systems, such as circulating helium in a gas-cooled reactor, to GIF COA accounts with functions similar to those in the PWR, e.g., Heat Rejection System Account 252. Annex I of the IAEA document (IAEA, 2000) gives a "dictionary" of accounts at the 3-digit level (nearly thirty pages long) and differs somewhat from the U.S. (EEDB) practice in the abbreviated three digit definitions below. At the two-digit level, all 2X accounts match the modified IAEA account system.

Account 1 – Pre-Construction Costs (CPC)

Account 11 – Land and Land Rights: (This is not in IAEA account system, but in EEDB 20; the EMWG decided to retain this scope in new account 11). This account includes the purchase of new land for the reactor site, including that needed for any co-located facilities, including dedicated fuel cycle facilities. Costs for acquisition of land rights should be included. This category does not include siting costs such as geo-technical work (account 211) or the preparation of environmental documentation (account 16).

Account 12 – Site Permits: This account includes costs associated with obtaining all site permits to permit construction of the permanent plant.

Account 13 – Plant Licensing: This account includes costs associated with obtaining plant licenses for construction and operation of the plant.

Account 14 – Plant permits: This account includes costs associated with obtaining all permits for construction and operation of the plant.

Account 15 – Plant studies: This account includes costs associated with plant studies performed for the site or plant in support of construction and operation of the plant.

Account 16 – Plant Reports*:* This account includes costs associated with production of major reports such as Environmental Impact Statement, Safety Analysis Report,

Accounts 17-18 – Other pre-construction costs

Account 19 – Contingency Pre-construction Costs: An assessment of additional cost that is necessary to achieve desired confidence level for the pre-construction costs not to be exceeded.

Account 2 – Capitalized Direct Costs (CDC)

Account 21 – Structures and Improvements: This account covers costs for civil work and civil structures, mostly buildings, exclusive of those for the cooling towers. Suggested 3-digit accounts are as follows:

Acct 211 **Site preparation/Yard work:** Includes clearing, grubbing, scraping, geo-technical work, site cut, fill and compact, drainage, fences, landscaping, etc.

Acct 212 **Reactor Island Civil Structures:** (Primary process facility) Includes concrete and metalwork, including installation labor, for the building surrounding and supporting the nuclear island, including the reactor containment structure. The biological shielding around the reactor core and the refueling canal are also included. For PWRs, the steam generators would be located inside this structure. Includes structural excavation and backfill, foundations, walls, slabs, siding, roof, architectural finishes, elevators, lighting, HVAC (general building service), fire protection, plumbing, drainage, etc.

Acct 213 **Turbine Generator Building:** (Secondary process facility). Includes the concrete and structural metalwork, including installation labor, for the building surrounding and supporting the turbine generator(s). For concepts that do not produce electricity, this account can be replaced with appropriate energy product buildings. Includes structural excavation and backfill, foundations, walls, slabs, siding, roof, architectural finishes, elevators, lighting, HVAC, fire protection, plumbing, drainage, etc.

The rest of the 21 series accounts are for other support buildings on the site. Those with a "*" after the account number are likely to be needed for all Generation IV systems. Modular concepts might have a separate building to house centralized functions for all modules, such as an external control room. Here, the building costs are for the complete civil structure, including structural excavation and backfill, foundations, finishes and building services such as elevators, lighting, HVAC, fire protection or domestic water and drainage, but do not include the specialized equipment within.

Acct 214* **Security Building and Gatehouse** houses the security force and support staff. The gatehouse controls entrance and egress to the site and visitor control functions.

Acct 215* **Reactor Service (Auxiliary) Building** houses the fuel storage area, the spent fuel pool, the control room, and most other BOP functions.

Acct 216* **Radwaste Building** accommodates the preparation and packaging of solid process wastes and maintenance wastes from reactor operations. This function could also be housed in the Auxiliary Building.

Acct 217 **Fuel Service Building:** (If separate, otherwise in Account 215).

Acct 218A **Control Building** houses the control room, if the control room structure is not part of Account 212.

Acct 218B* **Administration Building** houses the offices for management, administrative, engineering, clerical, finance, and other support staff.

Acct 218C **Operation and Maintenance Center** houses the O&M staff plus equipment for repair and maintenance of small equipment (if not in Account 215).

Acct 218E **Steam Generator Storage Building:** (For PWR concepts).

Acct 218K **Pipe Tunnels**

Acct 218L **Electrical Tunnels**

Acct 218N* **Maintenance Shop** includes maintenance and repair capability for large items, including a crane.

Acct 218Q* **Foundations for outside equipment and tanks**

Acct 218R **Balance of Plant Service Building** (if not in Account 215).

Acct 218S* **Wastewater treatment building**

Acct 218T **Emergency Power Generation Building** houses the gas turbines or diesel engines need to provide power to safety systems in the event of a reactor shutdown and loss of off-site power.

Acct 218W* **Warehouse**

Acct 218X* **Railroad tracks**

Acct 218Y* **Roads and paved areas**

Acct 218Z **Reactor Receiving and Assembly Building** (for modular concepts)

Acct 219A* **Training center**

Acct 219K* **Special material unloading facility**

Account 22 – Reactor Equipment: This category is most dependent on the reactor technology being considered, since the sub-account descriptions and costs depend heavily on the coolant used and whether the subsystems are factory-produced or constructed on site. For today's LWRs, the entire NSSS can be purchased as a unit from a reactor vendor. The RM may have its own COA structure for all the NSSS components. The list below attempts to be as generic as possible. The initial and reload fuel cores are not included here. (Fuel is discussed in Chapter 8).

Acct 221 **Reactor Equipment:** Includes the reactor vessel and accessories, reactor supports, reactor vessel internals (non-fuel), transport to site, in core reactor control devices, and the control rod systems.

Acct 222 **Main Heat Transport System:** Includes the initial reactor coolant load, the pressurizing or cover gas system, steam generators (if applicable), the reactor coolant piping system, the fluid drive circulation system (including pumps), heat exchangers, and in-system diagnostic instrumentation and metering. Also, includes main steam piping to turbine control and isolation valves (Account 231), as well as feedwater piping from feed heating system (Account 234).

Acct 223 **Safety Systems:** Includes the residual heat removal system, the safety injection system, any containment spray system, the combustible gas control system, and any associated heat exchangers, valves, pumps, pipes, and instruments.

Acct 224 **Radioactive Waste Processing Systems:** Includes liquid waste processing, the fission gas distribution and process system, and the solid radioactive waste system.

Acct 225 **Fuel Handling Systems:** Includes fuel handling and storage equipment, including cranes, fuel handling tools, service platforms, and fuel cleaning and inspection equipment.

Acct 226 **Other Reactor Plant Equipment:** Includes the inert gas system, make-up coolant systems, coolant treatment system, the auxiliary cooling system, maintenance equipment, and sampling equipment.

Acct 227 **Reactor Instrumentation and Control (I&C):** Includes benchboards, panels, racks, process computers, monitoring systems, plant control and protection system, I&C tubing and fittings, instrumentation, and software.

Acct 228 **Reactor Plant Miscellaneous Items:** Includes painting, welder qualification, and reactor plant insulation.

Account 23 – Turbine-Generator Equipment: This category assumes that electricity is the primary product. The categories below apply mostly to a steam-driven turbine; however, similar categories would exist for gas driven turbines, such as those in a MHTGR. *These categories will be expanded to include other energy product production systems.*

Acct 231 **Turbine Generator(s):** Includes turbine generator plus associated mountings, main steam control and isolation valves, lubrication system, gas systems, moisture separator, and drain system, excitation system and controls. Main steam piping is in Account 222.

Acct 233 **Condensing Systems:** Includes condenser equipment, the condensate system, the gas removal system, and the turbine bypass system. Includes condenser-cleaning system. Includes piping from condenser to feedwater heating system Account 234. Condensate polishing is in Account 235.

Acct 234 **Feed Heating Systems:** Includes the feed heating system, feed-water heaters, the feed-water system piping, the extraction steam system, and the feed-water heater vent and drain system. Piping to steam generator continues with Account 222.

Acct 235 **Other Turbine Plant Equipment:** Includes piping system, turbine auxiliaries, closed cooling water system, demineralized water make-up system, chemical treatment system, and neutralization system. (The cooling towers are in Account 25.)

Acct 236 **Instrumentation and control (I&C):** Includes turbine generator control equipment, process computer, and balance of plant instrumentation and controls, including software, tubing, fittings, etc. Cables are in Account 246.

Acct 237 **Turbine Plant Miscellaneous Items:** Includes painting, welder qualification, and turbine plant insulation.

Account 24 – Electrical Equipment: (Note: The IAEA account system normally puts all Instrumentation and Control here. The EMWG decided to retain I&C within the accounts that require I&C equipment, mainly Acct 227 and 236.) Accounts 21-23 all have interfaces with the power plant electrical service system and its associated equipment. This equipment is located both inside and outside the main reactor/balance of plant buildings.

Acct 241 **Switchgear:** Includes switch gear for generator and station service, generator transformer, auxiliary transformer, and connecting bus. (Typically to 10kV).

Acct 242 **Station service equipment:** Includes substations, auxiliary power sources, load centers, motor control centers, and station service and startup equipment, transformers and bus ducts. (Typically to 500V)

Acct 243 **Switchboards:** Includes control panels, and auxiliary power and signal boards. Includes batteries, DC equipment and non-interruptible power.

Acct 244 **Protective systems equipment:** Includes grounding systems, lightning protection, cathodic protection, heat tracing, freeze protection equipment, radiation monitoring, and environmental monitoring. Also includes equipment, raceway, cable and connections. Excludes communication systems (account 263) and building services such as lighting, HVAC, fire protection (which are included in their respective building accounts).

Acct 245 **Electrical Raceway Systems:** Includes cable tray, exposed conduits, embedded conduits, and underground conduit and duct systems. Also, includes fittings, supports, covers, boxes, manholes, ducts and accessories for the scheduled cable systems. Raceways for protective systems are in Account 244 and building services electrical systems are with their respective building accounts.

Acct 246 **Power and Control Cables and Wiring:** Typically includes all scheduled cable systems. Also, includes cable, straps, attachments, terminations, wire lugs, cable numbers, wire numbers, etc. Excludes lighting, communication and other protection systems.

Account 25 – Heat Rejection System: This account includes heat rejection equipment, including circulating water pumps, piping, valves and cooling towers. These may be required even if the plant does not produce electricity. (This is Account 26 in the original EEDB).

Acct 251 **Structures:** Includes structures for the makeup water and intake, the circulating water-pump house, the makeup water pretreatment building, and the cooling towers.

Acct 252 **Mechanical equipment**: Includes the heat rejection mechanical equipment, such as circulating water pumps, piping, valves, mechanical draft cooling towers, water treatment plant, intake water pumps, screens, filters, etc. Condensers are in Account 233. Natural draft towers are in Acct 251.

Account 26 – Miscellaneous Equipment: Covers items not in the categories above. (This is Account 25 in the original EEDB).

Acct 261 **Transportation and lift equipment**: Includes cranes and hoists. (Elevators are in their respective building accounts)

Acct 262 **Air, Water, Plant Fuel Oil, and Steam Service systems**

Acct 263 **Communications Equipment:** Includes telephones, radio, CCTV, strobe, public address, enunciator, and electronic access control and security systems.

Acct 264 **Furnishing and Fixtures:** Includes safety equipment, chemical laboratory, instrument shop equipment, maintenance shop equipment, office equipment and furnishings, change room, and dining facility equipment.

Account 27 – Special Materials: Covers non-fuel items such as heavy water, other special coolants, salts, etc., needed before start-up.

Account 28 – Simulator(s): Generation IV systems will require the development of new simulators for training operators.

Account 29 – Contingency –Direct Costs: An assessment of additional cost that might be necessary to achieve the desired confidence level for the direct costs not to be exceeded. Contingency is usually applied at an aggregated level, although its determination may include applying contingencies to individual high cost-impact items in the estimate. There are both deterministic and probabilistic methods for calculating its value. Deterministic methods require assessment of the maturity and complexity of the various aspects of the project and cost weighting of the base estimate. The probabilistic approach relies on statistical methods to determine uncertainty ranges for the key cost parameters affecting the base plus owner's costs. Contingency must have a statistical level of confidence associated with it, e.g., an 80% chance that a total cost will not overrun the base plus contingency sum. Appendix A discusses the issues associated with contingency determination.

F.4 Indirect Costs

In the original EEDB COA, the "ninety-X" series is reserved for the indirect costs of reactor construction. For the IAEA account system, it is the "thirty-X" and "forty-X" series. Nearly all these costs for the modified IAEA COA are associated with costs incurred by the architect/engineer/constructor firm that are not considered with "hands-on" construction. In the U.S., the percentage of funding dedicated to this area has increased for nuclear projects. More regulations and the need for more safety and quality assurance documentation have been the major contributors to this increase. For these accounts, the COA dictionary is expressed at the two-digit (COA 3X and 4X) levels.

Account 3 – Capitalized Indirect Services Cost (CIC)

Account 31 – Field Indirect Costs: This account includes cost of construction equipment rental or purchase, temporary buildings, shops, laydown areas, parking areas, tools, supplies, consumables, utilities, temporary construction, warehousing, and other support services. Account 31 also includes

- Temporary construction facilities, such as site offices, warehouses, shops, trailers, portable offices, portable restroom facilities, temporary worker housing, and tents.
- Tools and heavy equipment used by craft workers, rented equipment, such as cranes, bulldozers, graders, welders, etc. Typically, equipment with values of less than $1,000 are categorized as tools.
- Transport vehicles rented or allocated to the project, such as fuel trucks, flatbed trucks, large trucks, cement mixers, tanker trucks, official automobiles, buses, vans and light trucks.
- Expendable supplies, consumables, and safety equipment.
- Cost of utilities, office furnishings, office equipment, office supplies, radio communications, mail service, phone service, and construction insurance.
- Construction support services, temporary installations, warehousing, material handling, site cleanup, water delivery, road and parking areas maintenance, weather protection and repairs, snow clearing, maintenance of tools, and equipment.

Account 32 – Construction supervision: This account covers the direct supervision of construction (craft-performed) activities by the construction contractors or direct hire craft labor by the A/E contractor. The costs of the craft-laborers themselves are covered in the labor-hours component of the direct cost in Accounts 21-28 or in Account 31. This account covers work done at the site in what are usually temporary or rented facilities. It includes non-manual supervisory staff, such as field engineers and superintendents. Other non-manual field staff is included with account 38 PM/CM Services on-site.

Account 33 – Commissioning and Start-up Costs: Includes costs incurred by the A/E, reactor vendor, other equipment vendors, and Owner or Owners representative for startup of plant. This account includes:

- Startup Procedure development
- Trial test run services (Account 37 in the IAEA account system)
- Commissioning materials, consumables, tools, and equipment (Account 39 in the IAEA account system)
- The utility's (owner's) pre-commissioning costs are covered elsewhere in the TCIC sum as a supplemental cost (Account 41).

Account 34 – Demonstration Tests: All services necessary to perform the operation of the plant to demonstrate plant performance values and durations, including operations labor, consumables, spares, and supplies.

Account 35 – Design Services Offsite*:* This account covers engineering, design, and layout work that is not done at the reactor site, but at the architect/engineer/constructors' home office and the equipment/reactor vendor's home office. Often pre-construction design is included here. This project uses the IAEA format for standard plant (and equipment) design/construction/startup only, and not the FOAK design and certification effort. (FOAK work is in the one-time deployment phase of the project and not included in the standard plant direct costs. Design of the initial full size (FOAK) reactor, which will encompass multiple designs at several levels (pre-conceptual, conceptual, preliminary, etc.), will be a category of its own under FOAK cost and should be categorized separately. Site-related engineering and engineering effort (project engineering) required during construction of particular systems, which recur for all plants, as well as Q/A costs related to design, should be included here.

Account 36 – PM/CM Services Offsite: This account covers the costs for project management and management support on the above activities (Account 31) taking place at the reactor vendor, equipment suppliers', and A/E's home offices.

Account 37 – Design Services Onsite: These are the same items as in Account 35, except that they are conducted at the plant site office or on-site temporary facilities instead of at offsite office. Additional services include purchasing and clerical services.

Account 38 – PM/CM Services Onsite: This account covers the costs for project management and construction management support on the above activities (Account 33) taking place at the plant site. It includes staff for quality assurance, office administration, procurement, contract administration, HR department, labor relations, project control, medical and safety related activities. Craft supervisory personnel are with account 32.

Account 39 – Contingency on Indirect Services An assessment of additional cost that is necessary to achieve desired confidence level for the Support Services costs not to be exceeded.

<u>Account 4 – Capitalized Owner Cost (COC)</u>

Account 41 – Staff Recruitment and Training: This account should include costs for the recruitment and training of plant operators before plant start-up or commissioning activities (Account 37), or Demonstration Tests (Account 38).

Account 42 – Staff Housing: Includes relocation costs, camps, or permanent housing provided to permanent plant operations and maintenance staff.

Account 43 – Staff Salary Related Costs: Includes Taxes, Insurance, Fringes, Benefits, and any other salary related costs.

Account 44 – Other Owner Capitalized Costs

Account 49 – Contingency **on Owner Costs**: An assessment of additional costs that is necessary to achieve desired confidence level for the Operations costs not to be exceeded.

<u>Account 5 – Capitalized Supplementary Costs (CSC)</u>

Account 51 – Shipping and Transportation Costs: Includes shipping and transportation costs for major equipment or bulk shipments with freight forwarding.

Account 52 – Spare Parts: Includes spare parts furnished by system suppliers for first year of commercial operation. Excludes spare parts required for plant commissioning, startup, or demonstration run.

Account 53 – Taxes: Includes taxes associated with the permanent plant, such as property tax, to be capitalized with the plant.

Account 54 – Insurance: Includes insurance costs associated with the permanent plant to be capitalized with the plant.

Account 55 – Initial Core Load: This fuel is purchased by the utility before commissioning and is assumed a part of the TCIC. In the U.S., the initial core is not usually included in the design/construction (overnight) cost sum to which IDC (see below) is added. Since the first core, however, will likely have to be financed along with the design/construction/start-up costs, its cost is included in overnight costs in the present guidelines. It is included in "Capital at Risk" before revenues. The initial core cost is calculated with the formulas given in Chapter 8. This is a new account added to the modified IAEA account system.

Account 58 – Decommissioning Costs: Includes cost of decommissioning, decontamination, and dismantling the plant at the end of commercial operation, if it is capitalized with the plant. *(Question: I thought it was included in annual operating costs.)*

Account 59 – Contingency on Supplementary Costs: An assessment of additional cost necessary to achieve a desired confidence level for the Capitalized Supplementary Costs not to be exceeded. The contingency for the Initial Core Load should not be applied to this item, since the contingency is already imbedded in the fuel cycle costs from the Fuel Cycle Model**.**

Account 6 – Capitalized Financial Costs

Account 61 – Escalation: Typically excluded for a fixed year, constant dollar cost estimate, although it could be included in a business plan, financing proposal, or regulatory-related documents.

Account 62 – Fees: This account includes any fees or royalties applicable to plant that are to be capitalized with the plant.

Account 63 – Interest During Construction (IDC): This account is discussed in Chapter 6. IDC is applied to the sum of all up-front costs, i.e., accounts: (1 through 5) base costs, including respective contingencies. These costs are incurred before commercial operation and are assumed to be financed by a "construction loan." The IDC represents the "cost of the construction loan," e.g., its interest.

Account 69 – Contingency on Capitalized Financial Costs: An assessment of additional cost that is necessary to achieve desired confidence level for capitalized financial costs not to be exceeded, including schedule uncertainties.

Account 7 - Annualized Owner Cost (AOC)

Account 71 – Operations and Maintenance Staff: Salary costs of O&M Staff

Account 72 – Management Staff: Salary costs of Operations Management Staff

Account 73 – Salary Related Costs: Includes Taxes, Insurance, Fringes, Benefits, and any other annual salary related costs.

Account 74 – Operations Chemicals, Lubricants and Radwaste Management

Account 75 – Spare Parts

Account 76 – Utilities, Supplies, Consumables and purchased services

Account 77 – Capital Upgrades

Account 78 – Taxes and Insurance

Account 79 – Contingency on Annualized Owner Costs: An assessment of additional cost that is necessary to achieve desired confidence level for the Annualized O & M costs not to be exceeded.

Account 8 – Annualized Fuel Cost (ASC)

Account 81 – Refueling Operations: Incremental costs associated with refueling operations

Account 84 – Nuclear Fuel: Annualized costs associated with the fuel cycle.

Account 86 – Fuel Reprocessing Charges: Includes costs associated with storage and reprocessing charges for used fuel.

Account 89 – Contingency on Annualized Fuel Costs: An assessment of additional cost that is necessary to achieve desired confidence level for the Annualized Fuel Costs not to be exceeded.

Account 9 – Annualized Financial Costs (AFC)

Account 91 – Escalation: To be excluded from estimated costs for Generation IV nuclear energy systems, although it could be included in a business plan, financing proposal, or regulatory-related documents.

Account 92 – Fees

Account 93 – Cost of Money

Account 99 – Contingency Annualized Financial Costs: An assessment of additional costs that is necessary to achieve desired confidence level for the Annualized Financial Costs not to be exceeded, including schedule uncertainties.

F.5 Generalized Account Structure and Dictionary for Non-Electric Plant Capital Cost Estimates

It is recognized that most of the reactor fuels, fuel cycle services, and reactor components required for most Generation IV systems are not available today and are unlikely to be available in the next several years. There are also end use facilities for non-electric nuclear heat applications, such as thermal hydrogen, desalination, and actinide partitioning facilities that also have not yet been designed. In the course of preparing the Generation IV economic models, however, cost estimates for new facilities designed to fulfill these needs must be made. Below is the list of facilities for which life cycle (including TCIC) cost estimates will be needed.

- New factories (or modifications to existing ones) to produce the reactors for modular concepts.
- Regional or national fuel cycle facilities that may serve many reactors of a given type:
  ✓Aqueous fuel reprocessing plants
  ✓MOX fuel fabrication plants (e.g., pelletized or vibropack fuel)
  ✓MOX and uranium particle fuel fabrication plants (high-temperature reactors)
  ✓Actinide partitioning facilities
  ✓Spent fuel storage facilities
  ✓High-level waste storage facilities
- Fuel cycle facilities that will serve only the reactors on the plant site:
  ✓High-Pyrochemical reprocessing/re-fabrication facilities (e.g., for SFR/IFR)
  ✓Waste packaging facilities
  ✓On-site waste storage facilities
  ✓In-line reprocessing facilities located within reactor area (e.g., for the MSR)
- Non-electric End Use Facilities associated with dedicated reactor(s):
  ✓Thermochemical hydrogen production plant
  ✓Electrolytic hydrogen production plant
  ✓Water desalination plant

At the 2-digit level, the basic COA for these facilities can be similar to the electrical power plants. The only change would be in Accounts 23, which should now be called “Primary Product System Equipment” as opposed to “Turbine General Equipment.” Most other direct accounts (electrical, heat rejection/cooling, etc.) continue to support the primary processes. The indirect accounts serve the same purpose for other processes as they do for the electrical production plant.

As with the electrical production plant, life cycle levelized unit product costs (LUPC) must be calculated for other product plants. For fuel cycle facilities it will be necessary to calculate unit costs, such as $/kg heavy metal processed. Calculation of these unit costs requires distributing the capital and operating costs over a fixed number of reactors supported by the facility and its projected production lifetime. Chapter 8 discusses these fuel cycle costs. Similar unit cost calculations must also be done to obtain the costs of end-use commodities, such as hydrogen or desalinated water.

Guidelines for these accounts are presented below.

Table F.1 Comparison of COA Structure for Electric and Non-Electric Production Plants (Capitalized Costs)

Acct	A – ELECTRIC POWER PLANT		Acct	B – FUEL FABRICATION PLANT
A10	**Capitalized Pre-construction Costs**		**B10**	**Capitalized Pre-construction Costs**
A11	Land and Land Rights		B11	Land and Land Rights
A12	Site Permits		B12	Site Permits
A13	Plant Licensing		B13	Plant Licensing
A14	Plant Permits		B14	Plant Permits
A15	Plant Studies		B15	Plant Studies
A16	Plant Reports		B16	Plant Reports
A19	Contingency – Pre-Construction Cost		B19	Contingency – Pre-Construction Cost
A20	**Capitalized Direct Costs**		**B20**	**Capitalized Direct Costs**
A21	Structures and Improvements		B21	Structures and Improvements
A22	Reactor Plant Equipment		B22	Not Applicable
A23	Turbine - Generator Equipment		B23	Fuel Fabrication Process Equipment
A24	Electrical Equipment		B24	Electrical Equipment
A25	Heat Rejection/Cooling		B25	Heat Rejection/Cooling
A26	Miscellaneous Plant Equipment		B26	Miscellaneous Plant Equipment
A27	Special Materials		B27	Special Materials
A28	Simulator		B28	Simulator (if needed)
A29	Contingency Capitalized Direct Cost		B29	Contingency Capitalized Direct Cost
A30	**Support Services**		**B30**	**Support Services**
A31	Field Indirect Costs		B31	Field Indirect Costs
A32	Construction Supervision		B32	Construction Supervision
A33	Plant Commissioning Services		B33	Plant Commissioning Services
A34	Plant Demonstration Run		B34	Plant Demonstration Run
A35	Design Services Offsite		B35	Design Services Offsite
A36	PM/CM Services Offsite		B36	PM/CM Services Offsite
A37	Design Services Onsite		B37	Design Services Onsite
A38	PM/CM Services Onsite		B38	PM/CM Services Onsite
A39	Contingency - Indirect Services		B39	Contingency - Indirect Services
A40	**Capitalized Owner Cost**		B40	**Capitalized Owner Cost**
A41	Staff recruitment and training		B41	Staff recruitment and training
A42	Staff housing facilities		B42	Staff housing facilities
A43	Staff salary related costs		B43	Staff salary related costs
A46	Other owner's costs		B46	Other owner's costs
A49	Contingency –Owner Costs		B49	Contingency –Owner Costs

Acct	C – FUEL REPROCESSING PLANT		Acct	D – DESALINATION PLANT
C10	**Capitalized Pre-construction Costs**		**D10**	**Capitalized Pre-construction Costs**
C11	Land and Land Rights		D11	Land and Land Rights
C12	Site Permits		D12	Site Permits
C13	Plant Licensing		D13	Plant Licensing
C14	Plant Permits		D14	Plant Permits
C15	Plant Studies		D15	Plant Studies
C16	Plant Reports		D16	Plant Reports
C19	Contingency – Pre-Construction Cost		D19	Contingency – Pre-Construction Cost
C20	**Capitalized Direct Costs**		**D20**	**Capitalized Direct Costs**
C21	Structures and Improvements		D21	Structures and Improvements
C22	Not Applicable		D22	Reactor Plant Equipment
C23	Fuel Reprocessing Process Equipment		D23	Water Desalination Process Equipment
C24	Electrical Equipment		D24	Electrical Equipment
C25	Heat Rejection/Cooling		D25	Heat Rejection/Cooling
C26	Miscellaneous Plant Equipment		D26	Miscellaneous Plant Equipment
C27	Special Materials		D27	Special Materials
C28	Simulator		D28	Simulator (if needed)
C29	Contingency Capitalized Direct Cost		D29	Contingency Capitalized Direct Cost
C30	**Capitalized Indirect services**		**D30**	**Capitalized Indirect services**
C31	Field Indirect Costs		D31	Field Indirect Costs
C32	Construction Supervision		D32	Construction Supervision
C33	Plant Commissioning Services		D33	Plant Commissioning Services
C34	Plant Demonstration Run		D34	Plant Demonstration Run
C35	Design Services Offsite		D35	Design Services Offsite
C36	PM/CM Services Offsite		D36	PM/CM Services Offsite
C37	Design Services Onsite		D37	Design Services Onsite
C38	PM/CM Services Onsite		D38	PM/CM Services Onsite
C39	Contingency - Indirect Services		D39	Contingency - Indirect Services
C40	**Capitalized Owner Cost**		**D40**	**Capitalized Owner Cost**
C41	Staff recruitment and training		D41	Staff recruitment and training
C42	Staff housing facilities		D42	Staff housing facilities
C43	Staff salary related costs		D43	Staff salary related costs
C46	Other owner’s costs		D46	Other owner’s costs
C49	Contingency –Owner Costs		D49	Contingency –Owner Costs

	E – HYDROGEN GENERATION PLANT			F – OTHER PROCESS PLANT (Generic)
E10	**Capitalized Pre-construction Costs**		**F10**	**Capitalized Pre-construction Costs**
E11	Land and Land Rights		F11	Land and Land Rights
E12	Site Permits		F12	Site Permits
E13	Plant Licensing		F13	Plant Licensing
E14	Plant Permits		F14	Plant Permits
E15	Plant Studies		F15	Plant Studies
E16	Plant Reports		F16	Plant Reports
E19	Contingency – Pre-Construction Cost		F19	Contingency – Pre-Construction Cost
E20	**Capitalized Direct Costs**		**F20**	**Capitalized Direct Costs**
E21	Structures and Improvements		F21	Structures and Improvements
E22	Reactor Plant Equipment		F22	Reactor Plant Equipment
E23	Hydrogen Generation Process Equipment		F23	"Other Process" Process Equipment
E24	Electrical Equipment		F24	Electrical Equipment
E25	Heat Rejection/Cooling		F25	Heat Rejection/Cooling
E26	Miscellaneous Plant Equipment		F26	Miscellaneous Plant Equipment
E27	Special Materials		F27	Special Materials
E28	Simulator		F28	Simulator (if needed)
E29	Contingency Capitalized Direct Cost		F29	Contingency Capitalized Direct Cost
E30	**Capitalized Indirect services**		**F30**	**Capitalized Indirect services**
E31	Field Indirect Costs		F31	Field Indirect Costs
E32	Construction Supervision		F32	Construction Supervision
E33	Plant Commissioning Services		F33	Plant Commissioning Services
E34	Plant Demonstration Run		D34	Plant Demonstration Run
E35	Design Services Offsite		F35	Design Services Offsite
E36	PM/CM Services Offsite		F36	PM/CM Services Offsite
E37	Design Services Onsite		F37	Design Services Onsite
E38	PM/CM Services Onsite		F38	PM/CM Services Onsite
E39	Contingency - Indirect Services		F39	Contingency - Indirect Services
E40	**Capitalized Owner Cost**		F40	**Capitalized Owner Cost**
E41	Staff recruitment and training		F41	Staff recruitment and training
E42	Staff housing facilities		F42	Staff housing facilities
E43	Staff salary related costs		F43	Staff salary related costs
E46	Other owner's costs		F46	Other owner's costs
E49	Contingency –Owner Costs		F49	Contingency –Owner Costs

Table F.2 Estimate reporting format

		NUCLEAR ISLAND					BALANCE OF PLANT					
		FACTORY	SITE	SITE	SITE	NI	FACTORY	SITE	SITE	SITE	BOP	TOTAL
COA	Description	EQUIP	HOUR	LABOR	MATL	TOTAL	EQUIP	HOUR	LABOR	MATL	TOTAL	COST

Unit 1 - Recurring
Common - Recurring
TOTAL – Recurring

Unit 1 – Non-recurring
Common – Non-recurring
TOTAL – Non-recurring

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APPENDIX G
DATA FOR COST ESTIMATING

G.1 ESTIMATE PRICING BASIS DEFINITION

Table G.1.1 - 2001 composite labor crews and costs (USA) – As of January 1, 2001

Craft	Wage rate	Concrete Formwork, rebar, embeds, concrete		Structural Str. steel, misc. iron & architectural		Earthwork Clearing, excavation., backfill		Mechanical equipment Installation		Piping Installation		Instrument. Installation		Electrical Installation	
	$/h	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.
Boiler maker	34.90							15	5.23						
Carpenter	29.44	40	11.78	5	1.47									2	0.59
Electrician	34.64											70	24.25	96	33.26
Iron Worker	33.18	20	6.64	75	24.88			10	3.32						
Laborer	23.08	30	6.92	5	1.15	60	13.85							1	0.23
Millwright	30.86							25	7.71						
Operating Engineer	32.12	5	1.61	15	4.82	35	11.24	12	3.85	15	4.82	2	0.64	1	0.32
Pipe fitter	35.20							35	12.32	80	28.16	28	9.86		
Teamster	24.19					5	1.21	3	0.73	5	1.21				
Others	28.23	5	1.41												
		100	28.35	100	32.33	100	26.30	100	33.17	100	34.19	100	34.75	100	34.40

Table G.1.2 - 2001 composite labor crews and costs (Europe) – As of January 1, 2001

Craft	Wage rate	Concrete Formwork, rebar, embeds, concrete		Structural Str. steel, misc. iron & architectural		Earthwork Clearing, excavation., backfill		Mechanical equipment Installation		Piping Installation		Instrument. Installation		Electrical Installation	
	$/h	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.
Boiler maker	40.62							15	6.09						
Carpenter	34.26	40	13.70	5	1.71									2	0.69
Electrician	40.31											70	28.22	96	38.70
Iron Worker	38.61	20	7.72	75	28.96			10	3.86						
Laborer	26.86	30	8.06	5	1.34	60	16.12							1	0.27
Millwright	35.91							25	8.98						
Operating Engr.	37.38	5	1.87	15	5.61	35	13.08	12	4.49	15	5.61	2	0.75	1	0.37
Pipefitter	40.97							35	14.34	80	32.77	28	11.47		
Teamster	28.15					5	1.41	3	0.84	5	1.41				
Others	32.85	5	1.64												
		100	33.00	100	37.62	100	30.61	100	38.60	100	39.79	100	40.44	100	40.03

Table G.1.3 - 2001 composite labor crews and costs (Asia) – As of January 1, 2001
TO BE UPDATED

Craft	Wage rate	Concrete Formwork, rebar, embeds, concrete		Structural Str. steel, misc. iron & architectural		Earthwork Clearing, excavation., backfill		Mechanical equipment Installation		Piping Installation		Instrument. Installation		Electrical Installation	
	$/h	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.
Boiler maker	34.90							15	5.23						
Carpenter	29.44	40	11.78	5	1.47									2	0.59
Electrician	34.64											70	24.25	96	33.26
Iron Worker	33.18	20	6.64	75	24.88			10	3.32						
Laborer	23.08	30	6.92	5	1.15	60	13.85							1	0.23
Millwright	30.86							25	7.71						
Operating Engr.	32.12	5	1.61	15	4.82	35	11.24	12	3.85	15	4.82	2	0.64	1	0.32
Pipefitter	35.20							35	12.32	80	28.16	28	9.86		
Teamster	24.19					5	1.21	3	0.73	5	1.21				
Others	28.23	5	1.41												
		100	28.35	100	32.33	100	26.30	100	33.17	100	34.19	100	34.75	100	34.40

Table G.1.4 - Bulk commodity pricing (USA) – As of January 1, 2001

Commodity	Unit of measure	Nuclear $	Non-nuclear $
STRUCTURAL COMMODITIES			
Formwork	SM	30.00	28.00
Decking	SM	70.00	42.00
Reinforcing steel	MT	825.50	530.70
Embedded metal	KG	7.30	4.40
Concrete	CM	157.00	104.60
Structural steel	MT	3,656.00	1,651.00
Miscellaneous steel	MT	7,800.00	3,538.00
PIPING COMMODITIES			
50 mm. and under screwed pipe	LM	104.00	84.00
50 mm. and under CS welded pipe	LM	144.00	104.00
50 mm. and under CM welded pipe	LM	200.00	151.00
50 mm. and under SS welded pipe	LM	200.00	151.00
100 mm. CS sch 40 (0.237 in.) spooled pipe	LM	351.00	151.00
100 mm. CM sch 40 (0.237 in.) spooled pipe	LM	702.00	400.00
100 mm. SS sch 40 (0.237 in.) spooled pipe	LM	840.00	502.00
300 mm. CS sch 80 (0.688 in.) spooled pipe	LM	1,601.00	1,440.00
300 mm. CM sch 80 (0.688 in.) spooled pipe	LM	3,241.00	3,002.00
300 mm. SS sch 80 (0.688 in.) spooled pipe	LM	5,043.00	4,843.00
500 mm. CS sch 120 (1.50 in.) spooled pipe	LM	4,403.00	4,163.00
ELECTRICAL COMMODITIES			
50 mm. dia. rigid steel exposed conduit	LM	34.10	22.60
100 mm. dia. non-metallic duct bank conduit	LM	16.40	13.10
600 x 25 mm. aluminum cable tray	LM	73.50	48.90
600 volt power and control cable (Avg. 5 C, #12)	LM	9.50	7.50
600 volt instrumentation cable (Avg. 2 Pr., Shld, #18)	LM	4.90	3.90
5-15 kV power cable (Avg. 3 C, #250)	LM	24.90	20.00
600 volt connections	EA	2.80	1.40
5-15 kV connections	EA	131.00	90.00

SM = square meter, LM = linear meter, CM = cubic meter, KG = kilogram, MT = metric ton, EA = each

Table G.1.5 - Bulk commodity pricing (Europe) – As of January 1, 2001

Commodity	Unit of measure	Nuclear $	Non-nuclear $
STRUCTURAL COMMODITIES			
Formwork	SM	35.08	23.71
Decking	SM	81.43	55.05
Reinforcing steel	MT	960.76	649.58
Embedded metal	KG	8.47	5.72
Concrete	CM	182.66	123.50
Structural steel	MT	4,255.00	2,877.00
Miscellaneous steel	MT	8,233.00	5,568.00
PIPING COMMODITIES			
50 mm. and under screwed pipe	LM	121.04	81.83
50 mm. and under CS welded pipe	LM	167.62	113.33
50 mm. and under CM welded pipe	LM	232.91	157.47
50 mm. and under SS welded pipe	LM	232.91	157.47
100 mm. CS sch 40 (0.237 in.) spooled pipe	LM	408.55	276.22
100 mm. CM sch 40 (0.237 in.) spooled pipe	LM	817.10	552.45
100 mm. SS sch 40 (0.237 in.) spooled pipe	LM	977.46	660.87
300 mm. CS sch 80 (0.688 in.) spooled pipe	LM	1,863.00	1,260.00
300 mm. CM sch 80 (0.688 in.) spooled pipe	LM	3,772.00	2,551.00
300 mm. SS sch 80 (0.688 in.) spooled pipe	LM	5,869.00	3,968.00
500 mm. CS sch 120 (1.50 in.) spooled pipe	LM	5,124.00	4,464.00
ELECTRICAL COMMODITIES			
50 mm. dia. rigid steel exposed conduit	LM	39.71	26.85
100 mm. dia. non-metallic duct bank conduit	LM	19.09	12.91
600 x 25 mm. aluminum cable tray	LM	85.53	57.83
600 volt power and control cable (Avg. 5 C, #12)	LM	11.07	7.49
600 volt instrumentation cable (Avg. 2 Pr., Shld, #18)	LM	5.73	3.87
5-15 kV power cable (Avg. 3 C, #250)	LM	29.02	19.62
600 volt connections	EA	3.26	2.20
5-15 kV connections	EA	152.46	103.08

SM = square meter, LM = linear meter, CM = cubic meter, KG = kilogram, MT = metric ton, EA = each

Table G.1.6 - Bulk commodity pricing (Asia) – As of January 1, 2001
TO BE UPDATED

Commodity	Unit of measure	Nuclear $	Non-nuclear $
STRUCTURAL COMMODITIES			
Formwork	SM	30.00	28.00
Decking	SM	70.00	42.00
Reinforcing steel	MT	825.50	530.70
Embedded metal	KG	7.30	4.40
Concrete	CM	157.00	104.60
Structural steel	MT	3,656.00	1,651.00
Miscellaneous steel	MT	7,800.00	3,538.00
PIPING COMMODITIES			
50 mm. and under screwed pipe	LM	104.00	84.00
50 mm. and under CS welded pipe	LM	144.00	104.00
50 mm. and under CM welded pipe	LM	200.00	151.00
50 mm. and under SS welded pipe	LM	200.00	151.00
100 mm. CS sch 40 (0.237 in.) spooled pipe	LM	351.00	151.00
100 mm. CM sch 40 (0.237 in.) spooled pipe	LM	702.00	400.00
100 mm. SS sch 40 (0.237 in.) spooled pipe	LM	840.00	502.00
300 mm. CS sch 80 (0.688 in.) spooled pipe	LM	1,601.00	1,440.00
300 mm. CM sch 80 (0.688 in.) spooled pipe	LM	3,241.00	3,002.00
300 mm. SS sch 80 (0.688 in.) spooled pipe	LM	5,043.00	4,843.00
500 mm. CS sch 120 (1.50 in.) spooled pipe	LM	4,403.00	4,163.00
ELECTRICAL COMMODITIES			
50 mm. dia. rigid steel exposed conduit	LM	34.10	22.60
100 mm. dia. non-metallic duct bank conduit	LM	16.40	13.10
600 x 25 mm. aluminum cable tray	LM	73.50	48.90
600 volt power and control cable (Avg. 5 C, #12)	LM	9.50	7.50
600 volt instrumentation cable (Avg. 2 Pr., Shld, #18)	LM	4.90	3.90
5-15 kV power cable (Avg. 3 C, #250)	LM	24.90	20.00
600 volt connections	EA	2.80	1.40
5-15 kV connections	EA	131.00	90.00

SM = square meter, LM = linear meter, CM = cubic meter, KG = kilogram, MT = metric ton, EA = each

Table G.1.7 - Bulk commodity unit hour installation rates (USA)
(5 x 8 = 40 hour working week - replica plants)

Commodity	Unit of Measure	Nuclear	Non-nuclear
STRUCTURAL COMMODITIES			
Formwork – substructure	SM	6.89	5.17
Formwork – superstructure	SM	12.06	9.04
Decking	SM	1.72	1.29
Reinforcing steel – substructure	MT	29.03	21.77
Reinforcing steel – superstructure	MT	36.29	27.22
Embedded metal	KG	0.24	0.18
Concrete – substructure	CM	2.62	1.96
Concrete – superstructure	CM	5.23	3.92
Structural steel	MT	58.06	13.06
Miscellaneous steel	MT	108.86	54.32
PIPING COMMODITIES			
2 in. and under screwed pipe	LM	11.35	4.27
2 in. and under CS welded pipe	LM	17.00	6.36
2 in. and under CM welded pipe	LM	26.44	9.91
2 in. and under SS welded pipe	LM	34.02	12.76
4 in. CS sch 40 (0.237 in.) spooled pipe	LM	18.70	7.02
4 in. CM sch 40 (0.237 in.) spooled pipe	LM	44.98	16.86
4 in. SS sch 40 (0.237 in.) spooled pipe	LM	37.40	14.04
12 in. CS sch 80 (0.688 in.) spooled pipe	LM	44.00	16.50
12 in. CM sch 80 (0.688 in.) spooled pipe	LM	95.21	35.70
12 in. SS sch 80 (0.688 in.) spooled pipe	LM	87.99	33.01
20 in. CS sch 120 (1.50 in.) spooled pipe	LM	139.83	52.43
ELECTRICAL COMMODITIES			
2 in. dia. rigid steel exposed conduit	LM	4.13	1.90
4 in. dia. non-metallic duct bank conduit	LM	1.15	0.52
24 in. x 3 in. aluminum cable tray	LM	9.45	4.33
600 volt power and control cable	LM	0.43	0.20
600 volt instrumentation cable	LM	0.36	0.16
5-15 kV power cable	LM	1.77	0.82
600 volt connections	EA	0.88	0.41
5-15 kV connections	EA	20.80	9.40
INSTRUMENTATION			
Control panel	LM	314.96	118.11
Field-mounted instrument	EA	12.80	4.80
Instrument tube	LM	3.15	2.36

SM = square meter, LM = linear meter, CM = cubic meter, KG = kilogram, MT = metric ton, EA = each

Table G.1.8 - Bulk commodity unit hour installation rates (Europe)
(5 x 8 = 40 hour working week - replica plants)

Commodity	Unit of Measure	Nuclear	Non-nuclear
STRUCTURAL COMMODITIES			
Formwork – substructure	SM	6.89	5.17
Formwork – superstructure	SM	12.06	9.04
Decking	SM	1.72	1.29
Reinforcing steel – substructure	MT	29.03	21.77
Reinforcing steel – superstructure	MT	36.29	27.22
Embedded metal	KG	0.24	0.18
Concrete – substructure	CM	2.62	1.96
Concrete – superstructure	CM	5.23	3.92
Structural steel	MT	58.06	13.06
Miscellaneous steel	MT	108.86	54.32
PIPING COMMODITIES			
2 in. and under screwed pipe	LM	11.35	4.27
2 in. and under CS welded pipe	LM	17.00	6.36
2 in. and under CM welded pipe	LM	26.44	9.91
2 in. and under SS welded pipe	LM	34.02	12.76
4 in. CS sch 40 (0.237 in.) spooled pipe	LM	18.70	7.02
4 in. CM sch 40 (0.237 in.) spooled pipe	LM	44.98	16.86
4 in. SS sch 40 (0.237 in.) spooled pipe	LM	37.40	14.04
12 in. CS sch 80 (0.688 in.) spooled pipe	LM	44.00	16.50
12 in. CM sch 80 (0.688 in.) spooled pipe	LM	95.21	35.70
12 in. SS sch 80 (0.688 in.) spooled pipe	LM	87.99	33.01
20 in. CS sch 120 (1.50 in.) spooled pipe	LM	139.83	52.43
ELECTRICAL COMMODITIES			
2 in. dia. rigid steel exposed conduit	LM	4.13	1.90
4 in. dia. non-metallic duct bank conduit	LM	1.15	0.52
24 in. x 3 in. aluminum cable tray	LM	9.45	4.33
600 volt power and control cable	LM	0.43	0.20
600 volt instrumentation cable	LM	0.36	0.16
5-15 kV power cable	LM	1.77	0.82
600 volt connections	EA	0.88	0.41
5-15 kV connections	EA	20.80	9.40
INSTRUMENTATION			
Control panel	LM	314.96	118.11
Field-mounted instrument	EA	12.80	4.80
Instrument tube	LM	3.15	2.36

SM = square meter, LM = linear meter, CM = cubic meter, KG = kilogram, MT = metric ton, EA = each

Table G.1.9 - Bulk commodity unit hour installation rates (Asia)
(5 x 8 = 40 hour working week - replica plants)

TO BE UPDATED

Commodity	Unit of Measure	Nuclear	Non-nuclear
STRUCTURAL COMMODITIES			
Formwork – substructure	SM	6.89	5.17
Formwork – superstructure	SM	12.06	9.04
Decking	SM	1.72	1.29
Reinforcing steel – substructure	MT	29.03	21.77
Reinforcing steel – superstructure	MT	36.29	27.22
Embedded metal	KG	0.24	0.18
Concrete – substructure	CM	2.62	1.96
Concrete – superstructure	CM	5.23	3.92
Structural steel	MT	58.06	13.06
Miscellaneous steel	MT	108.86	54.32
PIPING COMMODITIES			
2 in. and under screwed pipe	LM	11.35	4.27
2 in. and under CS welded pipe	LM	17.00	6.36
2 in. and under CM welded pipe	LM	26.44	9.91
2 in. and under SS welded pipe	LM	34.02	12.76
4 in. CS sch 40 (0.237 in.) spooled pipe	LM	18.70	7.02
4 in. CM sch 40 (0.237 in.) spooled pipe	LM	44.98	16.86
4 in. SS sch 40 (0.237 in.) spooled pipe	LM	37.40	14.04
12 in. CS sch 80 (0.688 in.) spooled pipe	LM	44.00	16.50
12 in. CM sch 80 (0.688 in.) spooled pipe	LM	95.21	35.70
12 in. SS sch 80 (0.688 in.) spooled pipe	LM	87.99	33.01
20 in. CS sch 120 (1.50 in.) spooled pipe	LM	139.83	52.43
ELECTRICAL COMMODITIES			
2 in. dia. rigid steel exposed conduit	LM	4.13	1.90
4 in. dia. non-metallic duct bank conduit	LM	1.15	0.52
24 in. x 3 in. aluminum cable tray	LM	9.45	4.33
600 volt power and control cable	LM	0.43	0.20
600 volt instrumentation cable	LM	0.36	0.16
5-15 kV power cable	LM	1.77	0.82
600 volt connections	EA	0.88	0.41
5-15 kV connections	EA	20.80	9.40
INSTRUMENTATION			
Control panel	LM	314.96	118.11
Field-mounted instrument	EA	12.80	4.80
Instrument tube	LM	3.15	2.36

SM = square meter, LM = linear meter, CM = cubic meter, KG = kilogram, MT = metric ton, EA = each

Table G.1.10 - Commodity definitions

Description	Commodity content
FORMWORK	Supply, fabrication, preparation, assembly, installation, removal and disposal of forming material. Commodity starting point assumes that forms are wooden and reused.
DECKING	Supply, preparation, and installation of metal decking used to form concrete slabs. Decking is assumed to be galvanized steel, and to remain in place after concrete is set. Area take-off is exact, and material cost includes overlap, and waste, corrugated filler, spot welding, and other installation aids as needed.
REINFORCING STEEL	Supply of straight bars or vendor-bent bars of reinforcing steel, including necessary materials for supports and field joints. Weight take-off or estimate is for rebar only. Material cost includes supports, joints, and related additional material.
EMBEDDED METAL	Supply, preparation, and installation of embedment, including nelson studs or other weldments as needed. Includes sleeves, anchor plates, attachment plates.
CONCRETE	Supply, delivery, and placement within the site of mixed structural concrete, with nominal 3 000 psi motive compressive strength. Assumed mixed in a dedicated on-site batch plant. Values include heat control or ice addition, patch and sack, curing mixes, hardeners, expansion and construction or seismic joint materials, if needed.
STRUCTURAL STEEL	Supply, preparation, installation, alignment, and bolting or welding of prefabricated painted steel shapes and structures. Includes column base plates, grouting, touch-up painting, etc.
MISCELLANEOUS STEEL	Supply, preparation, installation, alignment, and bolting or welding of prefabricated painted steel shapes, structures, and components. This commodity includes stairs, platforms, hand railings, toe plate, door and opening frames, grating, checker plate, etc.
PIPING COMMODITIES	Piping commodities include pipe, fittings, hangers and supports, installation, alignment and tack-welding (when appropriate), welding, and post-weld heat treatment if necessary. Installation includes non-destructive testing, flushing, and hydro testing. Piping excludes the material cost of valves, but includes the installation labor for valves. Separate commodities are used for insulation, vacuum jacketing, heat tracing, and painting. Piping 50 mm. and smaller is predominantly supplied as straight run material and field fabricated or on-site pre-fabricated. Larger piping is predominantly shop prefabricated and supplied to the field as spool pieces. Only joints needed to allow shipping and installation are installed in the field.
ELECTRICAL CONDUIT	Supply and installation of electrical conduit, including hangers, supports, attachments, and fittings including installation devices such as pull boxes.
CABLE TRAY	Supply and installation of electrical cable tray and fittings, including hangers, supports, connecting pieces, barriers, covers, etc.

Table G.1.11 - Escalation adjustment factors[a]

Initial year[b]	Implicit price deflator[c]	Nuclear plant cost adjustment factors[d]					
		GIF Code of Account Number					
		21	22	23	24	25	Total
1992	1.191	1.336	1.235	1.311	1.381	1.330	1.285
1993	1.165	1.275	1.211	1.277	1.323	1.286	1.247
1994	1.137	1.207	1.165	1.211	1.293	1.231	1.195
1995	1.114	1.162	1.136	1.161	1.242	1.173	1.154
1996	1.091	1.142	1.112	1.151	1.189	1.163	1.133
1997	1.071	1.105	1.089	1.103	1.164	1.139	1.103
1998	1.052	1.090	1.073	1.082	1.138	1.106	1.084
1999	1.040	1.076	1.057	1.082	1.121	1.076	1.072
2000	1.024	1.037	1.037	1.039	1.077	1.041	1.042
2001	1.000	1.000	1.000	1.000	1.000	1.000	1.000

[a] Cost escalation factors from initial year to January 1, 2001.
[b] January 1 of dates shown.
[c] Increase from 4th quarter of year until 4th quarter of 2000.
[d] Source: Nuclear Production plant Electric Utility construction cost index for North Central region.

G.2 REFERENCE PLANT DATA

The following data is provided depicting US Nuclear plant construction experience. Much of the tabulated relationships may be influenced by US specific experience and subsequent evolution of construction practices, project design definitions and project control programs. The data may be useful as a validation tool with appropriate adjustments for GEN IV needs.

Table G.2.1 1970's LWR US Experience Data Single Unit Plant 588 MWe BWR, Fuel Load 2/74

SINGLE UNIT PLANT	Job No.		**SINGLE UNIT PLANT**			Unit	1	Material C.G		1989
7/1/1989 Material Pricing	Client					Net Mwe	552	Gross	588	BWR
$30/Hour Manual Labor	First Concrete		Jun-70			Fuel Load	Feb-74			-
$25/Hour Non-Manual Labor	**NORMALIZED DATA - EMWG FORMAT**									
1.6 Direct Productivity Factor	Std HR					US $				
COMMODITY % OF DIRECT	Std HR	P.F.	DH	SC	Total HR	Process Equip.	Labor	Material	SC Install	Total
Mechanical	5%	1.60	8%	2%	11%	33%	4%	5%	0%	42%
Concrete	13%	1.60	21%	1%	22%	0%	8%	3%	0%	12%
Structural Steel	1%	1.60	1%	3%	4%	0%	1%	3%	0%	5%
Other Civil/Architectural	5%	1.60	8%	4%	12%	0%	4%	4%	0%	8%
Piping	16%	1.60	26%	4%	30%	0%	11%	9%	0%	20%
Instrumentation	3%	1.60	4%	0%	4%	0%	2%	1%	0%	3%
Electrical	10%	1.60	16%	1%	17%	0%	6%	4%	0%	10%
Other Direct	0%	1.60	1%	0%	1%	0%	0%	0%	0%	0%
Total Direct	53%	1.60	85%	15%	100%	33%	38%	29%	0%	100%
Distrib Material	0%	-	0%	0%	0%	0%	0%	6%	0% `	
Distrib Manual Labor	11%	1.60	17%	3%	20%	0%	8%	0%	0%	8%
Field Office	13%	1.60	20%	0%	20%	0%	6%	1%	0%	8%
State Tax	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Living/Offshore Cost	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Distributable	23%	1.60	37%	3%	40%	0%	14%	7%	0%	21%
Total Field Cost	77%	1.60	122%	18%	140%	33%	52%	37%	0%	121%
H.O. Cost (Excluding Overhead and Fee)	22%	1.00	22%	0%	22%	0%	7%	2%	0%	9%
Total Project Cost	99%	1.47	145%	18%	163%	33%	59%	38%	0%	130%

Table G.2.2 1970's LWR US Experience Data Unit 1 of 2 - 1086 MWe BWR, Fuel Load 7/82

UNIT 1	Job No.	-	**TWO UNIT PLANT**			Unit	1	Material C.G		1989
7/1/1989 Material Pricing	Client	-				Net Mwe	1,086	Gross	588	BWR
$30/Hour Manual Labor	First Concrete		May-74			Fuel Load	Jul-82			
$25/Hour Non-Manual Labor	**NORMALIZED DATA - EMWG FORMAT**									
1.6 Direct Productivity Factor	Labor Hours					US $				
COMMODITY % OF UNIT 1 DIRECT	Std HR	P.F.	DH	SC	Total HR	Material	D.H. Labor	SC Material	SC Install	Total
Mechanical	4%	1.60	6%	8%	14%	39%	10%	2%	0%	50%
Concrete	12%	1.60	20%	0%	20%	0%	3%	6%	0%	9%
Structural Steel	4%	1.60	6%	2%	7%	0%	3%	2%	0%	4%
Other Civil/Architectural	4%	1.60	6%	1%	7%	0%	2%	2%	0%	4%
Piping	15%	1.60	24%	3%	27%	0%	12%	7%	0%	20%
Instrumentation	2%	1.60	2%	0%	2%	0%	2%	1%	0%	3%
Electrical	14%	1.60	22%	0%	22%	0%	4%	7%	0%	10%
Other Direct	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Direct	54%	1.60	86%	14%	100%	39%	35%	26%	0%	100%
Distrib Material	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Distrib Manual Labor	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Field Office	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
State Tax	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Living/Offshore Cost	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Distributable	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Field Cost	54%	1.60	86%	14%	100%	39%	35%	26%	0%	100%
H.O. Cost (Excluding Overhead and Fee)	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Project Cost	54%	1.60	86%	14%	100%	39%	35%	26%	0%	100%

Table G.2.3 1970's LWR US Experience Data Unit 2 of 2, 1086 MWe BWR, Fuel Load 3/84

UNIT 2	Job No.	-	**TWO UNIT PLANT**			Unit	2		Material C.G	1989
7/1/1989 Material Pricing	Client	-				Net Mwe	1,086	Gross	1,135	BWR
$30/Hour Manual Labor	First Concrete		Aug-74			Fuel Load	Mar-84			-
$25/Hour Non-Manual Labor	**NORMALIZED DATA - EMWG FORMAT**									
1.44 Direct Productivity Factor	Labor Hours					US $				
COMMODITY % OF UNIT 1 DIRECT	Std HR	P.F.	DH	SC	Total HR	Material	Labor	SC Material	SC Install	Total
Mechanical	4%	1.44	5%	8%	13%	39%	10%	2%	0%	50%
Concrete	12%	1.44	18%	0%	18%	0%	3%	5%	0%	8%
Structural Steel	4%	1.44	5%	2%	7%	0%	3%	2%	0%	4%
Other Civil/Architectural	4%	1.44	5%	1%	6%	0%	2%	2%	0%	4%
Piping	15%	1.44	21%	3%	24%	0%	12%	6%	0%	19%
Instrumentation	2%	1.44	2%	0%	2%	0%	2%	1%	0%	2%
Electrical	14%	1.44	20%	0%	20%	0%	4%	6%	0%	10%
Other Direct	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Direct	54%	1.44	77%	14%	91%	39%	35%	23%	0%	97%
Distrib Material	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Distrib Manual Labor	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Field Office	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
State Tax	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Living/Offshore Cost	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Distributable	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Field Cost	54%	1.44	77%	14%	91%	39%	35%	23%	0%	97%
H.O. Cost (Excluding Overhead and Fee)	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Project Cost	54%	1.44	77%	14%	91%	39%	35%	23%	0%	97%

Table G.2.4 1970's LWR US Experience Data Common for 2 x 1086 MWe BWR, Fuel Load 3/84

COMMON FOR TWO UNITS	Job No.	-	**TWO UNIT PLANT**			Unit C			Material C.G	1989
7/1/1989 Material Pricing	Client	-				Net Mwe	2,172	Gross	2,270	BWR
$30/Hour Manual Labor	First Concrete		May-74			Fuel Load	Mar-84			-
$25/Hour Non-Manual Labor	**NORMALIZED DATA - EMWG FORMAT**									
1.6 Direct Productivity Factor	Labor Hours					US $				
COMMODITY % OF UNIT 1 DIRECT	Std HR	P.F.	DH	SC	Total HR	Material	D.H. Labor	SC Material	SC Install	Total
Mechanical	1%	1.60	1%	0%	2%	1%	1%	0%	0%	2%
Concrete	16%	1.60	25%	0%	26%	0%	4%	8%	0%	11%
Structural Steel	4%	1.60	6%	2%	8%	0%	2%	2%	0%	3%
Other Civil/Architectural	7%	1.60	11%	5%	16%	0%	5%	3%	0%	9%
Piping	9%	1.60	14%	2%	16%	0%	7%	4%	0%	11%
Instrumentation	2%	1.60	3%	1%	4%	0%	3%	1%	0%	4%
Electrical	16%	1.60	26%	1%	27%	0%	8%	8%	0%	16%
Other Direct	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Direct	54%	1.60	86%	11%	98%	1%	29%	26%	0%	55%
Distrib Material	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Distrib Manual Labor	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Field Office	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
State Tax	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Living/Offshore Cost	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Distributable	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Field Cost	54%	1.60	86%	11%	98%	1%	29%	26%	0%	55%
H.O. Cost (Excluding Overhead and Fee)	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Project Cost	54%	1.60	86%	11%	98%	1%	29%	26%	0%	55%

Table G.2.5 1970's LWR US Experience Data Two units and Common 2 x 1086 MWe BWR, Fuel Load 7/82 & 3/84

TWO UNITS & COMMON	Job No.	-	**TWO UNIT PLANT**			Unit 1, 2, & C			Material C.G	1989
7/1/1989 Material Pricing	Client	-				Net Mwe	2,172	Gross	2,270	BWR
$30/Hour Manual Labor	First Concrete		May-74			Fuel Load	Mar-84			-
$25/Hour Non-Manual Labor	**NORMALIZED DATA - EMWG FORMAT**									
1.55 Direct Productivity Factor			Labor Hours					US $		
COMMODITY % OF UNIT 1 DIRECT	Std HR	P.F.	DH	SC	Total HR	Material	D.H. Labor	SC Material	SC Install	Total
Mechanical	8%	1.53	12%	17%	29%	78%	20%	4%	0%	102%
Concrete	41%	1.55	63%	0%	63%	0%	9%	19%	0%	28%
Structural Steel	11%	1.55	17%	5%	22%	0%	7%	5%	0%	12%
Other Civil/Architectural	14%	1.56	22%	8%	30%	0%	10%	7%	0%	16%
Piping	38%	1.54	59%	8%	67%	0%	32%	18%	0%	49%
Instrumentation	5%	1.55	8%	1%	9%	0%	6%	2%	0%	9%
Electrical	44%	1.55	68%	1%	69%	0%	15%	21%	0%	36%
Other Direct	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Direct	161%	1.55	249%	40%	289%	78%	99%	75%	0%	253%
Distrib Material	0%	-	0%	0%	0%	0%	21%	0%	0%	21%
Distrib Manual Labor	33%	1.60	53%	2%	55%	0%	1%	20%	0%	21%
Field Office	40%	1.60	64%	0%	64%	0%	6%	20%	0%	26%
State Tax	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Living/Offshore Cost	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Distributable	73%	1.60	117%	2%	118%	0%	28%	40%	0%	68%
Total Field Cost	234%	1.56	366%	42%	408%	78%	127%	115%	0%	321%
H.O. Cost (Excluding Overhead and Fee)	172%	1.00	172%	16%	188%	0%	34%	43%	0%	78%
Total Project Cost	406%	1.32	537%	58%	595%	78%	162%	158%	0%	398%

Table G.2.6 1970's LWR US Experience Data for 8 units 8,821 MWe LWR

AVERAGES per Net Kwe	Job No.	0%	**4 PLANTS**			Units	8		Material C.G	1989
7/1/1989 Material Pricing	Client	-	0%			Total Net Mwe	8,821	Average	1,103	LWR
$30/Hour Manual Labor	First Concrete		May-71			Last Fuel Load	Aug-89			-
$25/Hour Non-Manual Labor	**NORMALIZED DATA - EMWG FORMAT**					0%				
1.49 Direct Productivity Factor			Labor Hours					US $		
COMMODITY % OF DIRECT	Std HR	P.F.	DH	SC	Total HR	Material	D.H. Labor	SC Material	SC Install	Total
Mechanical	3%	1.49	5%	6%	10%	24%	4%	8%	0%	36%
Concrete	17%	1.49	25%	1%	26%	0%	9%	5%	0%	14%
Structural Steel	3%	1.49	5%	2%	7%	0%	2%	4%	0%	7%
Other Civil/Architectural	5%	1.45	8%	6%	14%	0%	5%	6%	0%	10%
Piping	14%	1.50	21%	2%	22%	0%	8%	9%	0%	17%
Instrumentation	2%	1.51	2%	0%	2%	0%	1%	3%	0%	4%
Electrical	12%	1.48	17%	0%	17%	0%	6%	5%	0%	11%
Other Direct	0%	1.58	0%	0%	0%	0%	0%	1%	0%	1%
Total Direct	56%	1.49	83%	17%	**100%**	24%	34%	42%	0%	**100%**
Distrib Material	0%	-	0%	0%	0%	0%	0%	8%	0%	8%
Distrib Manual Labor	11%	1.49	17%	1%	18%	0%	6%	0%	0%	6%
Field Office	13%	1.49	20%	0%	20%	0%	6%	2%	0%	8%
State Tax	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Living/Offshore Cost	0%	-	0%	0%	0%	0%	0%	0%	0%	0%
Total Distributable	24%	1.49	36%	1%	38%	0%	12%	10%	0%	22%
Total Field Cost	80%	1.49	119%	24%	143%	24%	46%	52%	0%	122%
H.O. Cost (Excluding Overhead and Fee)	46%	1.00	46%	0%	46%	0%	14%	5%	0%	19%
Total Project Cost	126%	1.31	165%	24%	189%	24%	60%	57%	0%	141%

Table G.2.7 1970's LWR US Experience Data Building Data

US PLANT DATA	BWR		PWR		LWR		TOTAL
Nominal Mwe	< 1,000	1,000 >	< 1,000	1,000 >	< 1,000	1,000 >	ALL
Net Mwe rating	545 - 945	1074 - 1308	440 - 933	1116 - 1311	440 - 945	1074 - 1311	545 - 1311
Fuel Load	9/70 - 3/82	8/73 - 8/89	4/68 - 8/85	11/75 - 2/89	4/68 - 8/85	8/73 - 8/89	4/68 - 8/89
Number of Units	5	10	22	12	27	22	49
Total Mwe	1,755	11,408	12,098	14,559	13,853	25,967	39,820
Average Mwe	351	1,141	550	1,213	513	1,180	813
AVERAGES							
Plot Area (1,000 SF)							
NI	39.0	62.5	39.3	100.2	39.2	83.0	58.9
BOP	32.7	52.4	33.4	57.3	33.2	55.1	43.1
Total	71.7	114.9	72.6	157.5	72.4	138.1	101.9
Building Volume (1,000,000 CF)							
NI	3.8	8.0	4.1	10.0	4.0	9.1	6.3
BOP	3.1	6.6	2.9	5.9	3.0	6.2	4.4
Total	6.9	14.6	7.0	15.9	7.0	15.3	10.7
Building Volume CF/Net KW							
NI	6.6	7.0	5.6	8.3	5.8	7.7	6.7
BOP	5.3	5.8	4.0	4.8	4.2	5.3	4.7
Total	11.9	12.8	9.6	13.1	10.0	13.0	11.4
Concrete (1,000 CY)							
Reactor Building	31.7	48.4	28.8	38.4	29.3	43.0	35.4
Major Auxiliary Buildings	12.7	50.0	21.8	65.5	20.1	58.5	37.3
Turbine Generator Building	16.3	45.6	11.6	23.3	12.5	33.4	21.9
Turbine Generator Pedestal	2.3	7.4	4.2	8.9	3.9	8.2	5.8
Other	13.0	44.4	25.9	42.0	23.5	43.1	32.3
Total	76.0	195.7	92.4	182.9	89.3	188.7	134.0
Concrete CY/Net Kw							
Reactor Building	54.7	43.7	33.2	31.5	37.2	37.0	37.1
Major Auxiliary Buildings	21.4	56.4	25.2	53.4	24.5	54.7	38.1
Turbine Generator Building	28.1	40.2	14.0	17.0	16.6	27.6	21.5
Turbine Generator Pedestal	4.0	6.6	4.8	7.2	4.6	6.9	5.7
Other	22.8	39.4	27.5	34.1	26.6	36.5	31.1
Total	130.9	173.2	104.7	152.8	109.6	162.1	133.2
Concrete CY/Building 1,000 CF							
Reactor Building	4.6	3.0	3.8	2.8	3.9	2.9	3.5
Major Auxiliary Buildings	1.8	2.4	2.7	4.2	2.6	3.4	2.9
Turbine Generator Building	2.4	2.7	1.4	1.6	1.6	2.1	1.8
Turbine Generator Pedestal	0.3	0.5	0.6	0.6	0.5	0.5	0.5
Other	1.9	2.6	2.8	2.9	2.7	2.8	2.7
Total	11.0	12.5	11.3	11.3	11.3	11.8	11.5
Structural Steel (TN)							
Supports	3,239	11,635	3,593	8,178	3,528	9,749	6,321
Miscellaneous Steel	226	1,712	601	2,078	531	1,912	1,151
Shield Plate	76	379	4,194	10,256	3,431	5,766	4,480
Total	3,541	13,642	7,788	20,512	7,002	17,389	11,665
Structural Steel LB / Net KW							
Supports	11.1	20.4	8.3	13.6	8.8	16.7	12.3
Miscellaneous Steel	0.8	3.0	1.3	3.4	1.2	3.3	2.1
Shield Plate	0.3	0.7	9.6	17.1	7.9	9.6	8.7
Total	12.1	23.9	19.2	34.1	17.9	29.5	23.1
Structural Steel TN/Building 1,000 CF							
Supports	0.45	0.80	0.39	0.52	0.40	0.65	0.51
Miscellaneous Steel	0.03	0.12	0.07	0.13	0.06	0.12	0.09
Shield Plate	0.01	0.02	0.46	0.65	0.38	0.36	0.37
Total	0.50	0.94	0.85	1.30	0.79	1.13	0.94

G.3 REFERENCE PLANT DATA UTILIZATION

The following table provides different basis and cost development techniques that may be utilized for development estimated costs for different components of a subject plant scope.

Table G.3.1 Example reference plant data utilization

Subject Plant Scope	Scope Basis	Estimate Method	Normalized data base	Parameter Cost Factors	Equipment cost	Material cost	Hours
Site	Site plan	Bottom-up				Unit prices	Unit Hours
BOP Facilities	Arrangement drawings	Bottom-up				Unit prices	Unit Hours
NI Facilities	Arrangement Drawings	Bottom-up				Unit prices	Unit Hours
Reactor Vessel	Conceptual drawings	Equipment Model	Historical data	Vendor input	Equipment cost model with current pricing		
Reactor Internals	Plant A and specific concepts	Equipment Model	A. Global	Parameter 1	Equipment cost model with estimates		
Reactor cooling systems	Plant B	Top-down System	B. Global	Parameter 2	Plant B	Plant B	Plant B
Reactor protection systems	Plant B	Top-down System	B. Global	Parameter 3	Plant B	Plant B	Plant B
Fuel handling system	Plant C	Top-down System	C. Global	Parameter 4	Plant C	Plant C	Plant C
Other reactor systems	Plant D	Top-down System	D. Global	Parameter 5	Plant D	Plant D	Plant D
Radwaste	Plant E	Top-down COA	E. Global	Parameter 6	Plant E	Plant E	Plant E
T/G Systems	Plant F	Top-down System	F. Global	Parameter 7	Plant F	Plant F	Plant F
Electrical Distrib.	Single line	Bulk Factor	G. Global	$ and Hr per $1000 Equipment		$/$1000 equipment	Hr/$1000 equipment
Electrical services	Facility services	Bulk Factor	H. Global	$ and Hr per Floor Area		$/Floor Area	Hr/Floor Area
Control Systems	Plant G	Bulk Factor	I. Global	$ and Hr per $1000 Equipment		$/$1000 equipment	Hr/$1000 equipment

Example of a top-down cost estimate development for a Nuclear Steam Supply System, utilizing cost estimate details from a suitable reference plant. Table G.3.2 shows the major cost adjustment parameters and indexes for each cost component.

Table G.3.2 Sample reference plant Data utilization

PROJECT : -	Reference 1											
TYPE	ALMR - NOAK											
COST DATE:	Oct-87											
Currency	US$	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Cost Index #		abc	TPO-N	$/Hr	def	NI	ghi	TPO-F	$/Hr	klm	BOP	PLT
Cost Index Value		145	1.60	27.74	235	138	305	1.2	28.29	425	138	138
Region Factor	Region 1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Plant maturity	NOAK	NOAK	NOAK	NOAK	NOAK	NOAK	NOAK	NOAK	NOAK	NOAK	NOAK	NOAK
RATING MWe		465	465	465	465	465	465	465	465	465	465	465
		REFERENCE PLANT COST DATA										
		NUCLEAR ISLAND (NI)					BALANCE OF PLANT (BOP)					
COA		FACTORY	SITE	SITE	SITE	NI	FACTORY	SITE	SITE	SITE	BOP	TOTAL
Number	Description	EQUIP	HOUR	LABOR	MATL	TOTAL	EQUIP	HOUR	LABOR	MATL	TOTAL	COST
220A.211	Reactor vessels	14,559										
220A.212	Reactor internals	42,793										
220A.213	Control Rod Drives	6,471										
220A.214	Incore Monitoring	3,328										
220A.221	Primary heat transport system	22,558										
220A.222	Intermediate heat transport system	29,845										
220A.223	Steam generator system	22,138					27,843					
220A.231	Back-up heat removal system						1,164					
220A.25	Fuel handling and storage						6,652					
220A.261	Inert gas receiving & processing						918					
220A.264	Sodium storage, relief and makeup						1,041					
220A.265	Sodium purification system						4,792					
220A.266	Na leak detection system						1,715					
220A.268	Maintenance equipment						21,564					
220A.269	Impurity monitoring						4,058					
220A.27	Instrumentation and Control						14,578					
220A.31	Support engineering						16,700					
220	Nuclear Steam Supply (NSSS)	141,692	1	17	4	141,713	101,025					141,713
221	Reactor equipment	15	49	1,334	4	1,353					-	1,353
222	Main heat transport system		28	755	4	759	65	167	4,714	6	4,785	5,544
223	Safeguards system		9	233	38	271					-	271
224	Radwaste system	360	6	164	57	581	104	1	39	16	159	740
225	Fuel handling	4,595	12	329	4	4,928					-	4,928
226	Other reactor plant equipment	49	28	791	99	939	36	2	57	25	118	1,057
227	Reactor I&C	21	59	1,684	583	2,288					-	2,288
228	Reactor plant miscellaneous items		56	1,572	1,218	2,790					-	2,790
	Module installation											-
22	REACTOR PLANT EQUIPMENT	146,732	248	6,879	2,011	155,622	101,230	170	4,810	47	5,062	160,684

Table G.3.3 shows the development of cost factor for each detail account.

Table G.3.3 Sample reference plant – Cost factor development

COA		REFERENCE PLANT TO SUBJECT PLANT COST FACTORS						COMPONENT COST FACTOR		
Number	Description	Parameter	Ref Plant Value	Subject Value	Parameter Ratio	Cost Factor Exponent	Cost Factor	FACTORY EQUIP	SITE HOUR	SITE MATL
220A.211	Reactor vessels	Ton	100	150	1.50	0.70	1.33	1.33	-	-
220A.212	Reactor internals	Ton	100	150	1.50	0.70	1.33	1.33	-	-
220A.213	Control Rod Drives	Ea	27	35	1.30	0.90	1.26	1.26	-	-
220A.214	Incore Monitoring	MWth	605	845	1.40	0.60	1.22	1.22	-	-
220A.221	Primary heat transport system	MWth	605	845	1.40	0.60	1.22	1.22	-	-
220A.222	Intermediate heat transport system	MWth	605	845	1.40	0.60	1.22	1.22	-	-
220A.223	Steam generator system	MWth	605	845	1.40	0.60	1.22	1.22	-	-
220A.231	Back-up heat removal system	MWth	605	845	1.40	0.60	1.22	1.22	-	-
220A.25	Fuel handling and storage	MWth	605	845	1.40	0.60	1.22	1.22	-	-
220A.261	Inert gas receiving & processing	Ton	100	125	1.25	0.70	1.17	1.17	-	-
220A.264	Sodium storage, relief and makeup	Ton	100	125	1.25	0.70	1.17	1.17	-	-
220A.265	Sodium purification system	Ton	100	125	1.25	0.70	1.17	1.17	-	-
220A.266	Na leak detection system	Mwe	465	650	1.40	0.60	1.22	1.22	-	-
220A.268	Maintenance equipment	Lot	1.00	1.25	1.25	1.00	1.25	1.25	-	-
220A.269	Impurity monitoring	Lot	1.00	1.25	1.25	1.00	1.25	1.25	-	-
220A.27	Instrumentation and Control	Mwe	465	650	1.40	0.60	1.22	1.22	-	-
220A.31	Support engineering	Lot	1.00	1.5	1.50	1.00	1.50	1.50	-	-
220	Nuclear Steam Supply (NSSS)	MWth	605	845	1.40	0.60	1.22	1.22	1.34	1.22
221	Reactor equipment	MWth	605	845	1.40	0.60	1.22	1.22	1.34	1.22
222	Main heat transport system	MWth	605	845	1.40	0.60	1.22	1.22	1.34	1.22
223	Safeguards system	%	0.17%	0.15%	0.89	1.00	0.89	-	0.98	0.89
224	Radwaste system	MWth	605	845	1.40	0.80	1.31	1.31	1.44	1.31
225	Fuel handling	MWth	605	845	1.40	0.50	1.18	1.18	1.30	1.18
226	Other reactor plant equipment	Reactor $	0.66%	0.45%	0.68	1.00	0.68	0.68	0.75	0.68
227	Reactor I&C	Reactor $	1.42%	0.90%	0.63	1.00	0.63	0.63	0.70	0.63
228	Reactor plant miscellaneous items	Reactor $	1.74%	1.10%	0.63	1.00	0.63	-	0.70	0.63
	Module installationm									
22	REACTOR PLANT EQUIPMENT									

Table G.3.4 shows the resultant subject plant cost estimate after application of the cost factors to the reference plant cost details.

Table G.3.4 Sample subject plant – Subject plant estimate

PROJECT : -	Subject Plant 1											
TYPE	LMFR - FOAK											
COST DATE:	Jan-01											
Currency	US $	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Cost Index #		abc	TPO-N	$/Hr	def	NI	ghi	TPO-F	$/Hr	klm	BOP	PLT
Cost Index Value		178	1.80	34.12	247	173	375	1.40	34.80	523	354	245
Region Factor	Region 2	1.0500	1.1250	1.2300	1.0500	1.0575	1.0000	1.1667	1.2300	1.0000	1.0144	1.0402
Plant maturity	FOAK	1.1000	1.2500	1.0000	1.1000	1.0958	1.1500	1.2500	1.0000	1.1000	1.1406	1.1138
RATING MWe		650	650	650	650	650	650	650	650	650	650	650
		SUBJECT PLANT CALCULATED										
		NUCLEAR ISLAND					BALANCE OF PLANT					
COA	Description	FACTORY EQUIP	SITE HOUR	SITE LABOR	SITE MATL	NI TOTAL	FACTORY EQUIP	SITE HOUR	SITE LABOR	SITE MATL	BOP TOTAL	TOTAL COST
220A.211	Reactor vessels	27,472	-	-	-	27,472	-	-	-	-	-	27,472
220A.212	Reactor internals	80,747	-	-	-	80,747	-	-	-	-	-	80,747
220A.213	Control Rod Drives	11,612	-	-	-	11,612	-	-	-	-	-	11,612
220A.214	Incore Monitoring	5,780	-	-	-	5,780	-	-	-	-	-	5,780
220A.221	Primary heat transport system	39,180	-	-	-	39,180	-	-	-	-	-	39,180
220A.222	Intermediate heat transport system	51,836	-	-	-	51,836	-	-	-	-	-	51,836
220A.223	Steam generator system	38,450	-	-	-	38,450	48,150	-	-	-	48,150	86,600
220A.231	Back-up heat removal system	-	-	-	-	-	2,013	-	-	-	2,013	2,013
220A.25	Fuel handling and storage	-	-	-	-	-	11,504	-	-	-	11,504	11,504
220A.261	Inert gas receiving & processing	-	-	-	-	-	1,518	-	-	-	1,518	1,518
220A.264	Sodium storage, relief and makeup	-	-	-	-	-	1,705	-	-	-	1,705	1,705
220A.265	Sodium purification system	-	-	-	-	-	9,264	-	-	-	9,264	9,264
220A.266	Na leak detection system	-	-	-	-	-	2,966	-	-	-	2,966	2,966
220A.268	Maintenance equipment	-	-	-	-	-	38,128	-	-	-	38,128	38,128
220A.269	Impurity monitoring	-	-	-	-	-	7,175	-	-	-	7,175	7,175
220A.27	Instrumentation and Control	-	-	-	-	-	25,210	-	-	-	25,210	25,210
220A.31	Support engineering	-	-	-	-	-	25,050	-	-	-	25,050	25,050
220	Nuclear Steam Supply (NSSS)	255,077	2	68	6	255,151	172,683	-	-	-	172,683	427,834
221	Reactor equipment	26	93	3,173	6	3,205	-	-	-	-	-	3,205
222	Main heat transport system	-	53	1,808	6	1,814	112	328	11,415	10	11,537	13,351
223	Safeguards system	-	12	409	41	450	-	-	-	-	-	450
224	Radwaste system	669	12	409	90	1,168	192	2	70	28	290	1,458
225	Fuel handling	7,718	22	751	6	8,475	-	-	-	-	-	8,475
226	Other reactor plant equipment	48	30	1,024	82	1,154	35	2	70	23	128	1,282
227	Reactor I&C	19	58	1,979	447	2,445	-	-	-	-	-	2,445
228	Reactor plant miscellaneous items	-	55	1,876	936	2,812	-	-	-	-	-	2,812
	Module installation					-					-	-
22	REACTOR PLANT EQUIPMENT	263,557	337	11,497	1,620	276,674	173,022	332	11,555	61	184,638	461,312

Table G.3.5 shows the extrapolation of the monolithic plant, reference plant cost adjustments for equivalent factory produced modules based on engineering judgment percentages for of each account that is intended to be modularized. Site labor is converted to shop labor and together with shop overheads is tabulated as factory equipment costs.

Table G.3.5 Sample subject plant estimate - Modularized plant cost development

PROJECT : -		
TYPE		
COST DATE:	**MODULARIZATION**	
Currency	Shop factors	
Cost Index #	0.90	Bulks
Cost Index Value	0.50	Productivity
Region Factor	12.50	$/Hr
Plant maturity	200%	O/H
RATING MWe		

			SUBJECT PLANT CALCULATED (MODULARIZED)										
COA		%	NUCLEAR ISLAND					BALANCE OF PLANT					
		Factory	FACTORY	SITE	SITE	SITE	NI	FACTORY	SITE	SITE	SITE	BOP	TOTAL
Number	Description	Module	EQUIP	HOUR	LABOR	MATL	TOTAL	EQUIP	HOUR	LABOR	MATL	TOTAL	COST
220A.211	Reactor vessels		% of Equipment included in Module at same cost as Field Equipment	Field Hours x % modular x ratio of productivity factors Shop/Field	Shop hours x Shop $/Hour + Shop Overhead % of Shop Labor Cost	Field Material x Factor for shop economy (waste & loss)							
220A.212	Reactor internals												
220A.213	Control Rod Drives												
220A.214	Incore Monitoring												
220A.221	Primary heat transport system												
220A.222	Intermediate heat transport system												
220A.223	Steam generator system												
220A.231	Back-up heat removal system												
220A.25	Fuel handling and storage												
220A.261	Inert gas receiving & processing												
220A.264	Sodium storage, relief and makeup												
220A.265	Sodium purification system	Direct	86,342	0.28	3.47	2.7	86,348						
220A.266	Na leak detection system	O/H			6.94		7						
220A.268	Maintenance equipment	Shop	86,342	0.28	10.42	2.70	86,355						
220A.269	Impurity monitoring		86,355										
220A.27	Instrumentation and Control												
220A.31	Support engineering	Field	168,736	1.00	34.12	3.00							
220	Nuclear Steam Supply (NSSS)	50%	255,090	1.00	34.12	3.00	255,127	172,683	-	-	-	172,683	427,810
			Composite Equipment cost (Module + Field Equipment)	Field Hours only	Field Labor Cost only	Field Material cost only							
221	Reactor equipment	70%	708	28	952	2	1,662	-	-	-	-	-	1,662
222	Main heat transport system	80%	446	11	362	1	809	3,633	66	2,283	2	5,918	6,727
223	Safeguards system	100%	162	-	-	-	162	-	-	-	-	-	162
224	Radwaste system	65%	803	4	143	32	978	226	1	24	10	260	1,238
225	Fuel handling	90%	7,929	2	75	1	8,005	-	-	-	-	-	8,005
226	Other reactor plant equipment	60%	280	12	409	33	722	63	1	28	9	101	823
227	Reactor I&C	60%	623	23	792	179	1,593	-	-	-	-	-	1,593
228	Reactor plant miscellaneous items	50%	708	28	938	468	2,114	-	-	-	-	-	2,114
	Module installation	10%		23	785	71	856		26	905	2	907	1,763
22	REACTOR PLANT EQUIPMENT		266,748	132	4,490	789	272,027	176,606	93	3,240	23	179,869	451,896

Sum of Field Equipment (AD)
AE (Field hours) x $AP (% Module) x AP6 (Shop Prod) / AE$6 (Field Prod) x AP7 (Shop $/Hr) x (1+$AP$8 (Overhead))
AG (Field Matl) x $AP (% Module) x AP5 (Shop Bulks %)
AE (Field Hrs) x (1 -$AP (%Mod))
AR (Calc Hrs) x AF$6 (Field $/Hr)
AG (Field Mtl) x (1 - $AP (% Mod))

The resultant cost shows a minor (451,896/461,312 = -2%) cost benefit at the direct cost level with a more significant benefit to be derived from a reduced construction schedule and associated indirect costs as well as cost of money.

G.4 ESTIMATE VALIDATION

Major estimate and plant parameters are to be tabulated with comparison to reference plant data. Major differences should be explained with supporting data. Some or all of the following parameter checks can be implemented.

1. Parameters per kWe for - Process equipment cost, material cost, direct hours, direct cost, COA summary, category costs. See tables G.2.1 through G.2.6.
2. Bulk ratios to process equipment – Materials per $1,000 of Process equipment cost, Installation hours per $1,000 of process equipment cost.
3. Indirect cost ratios to direct cost – Total field indirect COA cost percentage of total direct cost, total field indirect COA cost percentage of total direct hours, field indirect COA total hour percentage of total direct hours. See tables G.2.1 through G.2.6 for 1970's US nuclear plant experience data.
4. Ratios to reference plant summary COA – Comparison of major COA summaries to reference plant data.
5. Category cost percentages of total direct cost – Distribution of direct and indirect cost by category of work with percentages relative to total direct cost. See tables G.2.1 through G.2.6 for 1970's US nuclear plant experience data.
6. Productivity comparison data – Tabulation of sample unit rates and other productivity data with comparisons to reference plant data and actual industry experience.
7. Equipment and material pricing data – Tabulation of major equipment and material pricing data with comparisons to reference plant data and current industry data.
8. Bulk commodity quantity data – Tabulation of major commodity quantities with appropriate ratios to plant rating, building volumes or other parameter and comparisons with reference plant data. See table G.2.7 for 1970's US nuclear plant experience data.
9. Area/Volume data – Tabulation of major facility plan area, floor area and building volumes with ratios to plant ratings and comparisons with reference plant data. See table G.2.7 for 1970's US nuclear plant experience data

APPENDIX H

TOP-DOWN ESTIMATING PROCESS

H. 1 - Examples of cost estimating methods

H.1.1 - Global and specific models for PWRs

Existing models come from PWR data, which are numerous enough to validate cost models, in a large range of reactor power.

The global model established for a PWR 900 MWe construction cost is a reference for PWRs. The elaboration of this global model has included the development of specific models for primary vessel, steam generators, pressurizer, nuclear circuits, civil works, and more global models for conventional island, BOP, etc. We have utilized every useful data, composite rates or more or less simple models validated on PWRs cost data.

The same process has allowed elaborating, marginally with regard to reference PWR 900 MWe, models for 1300 MWe and 1450 MWe PWRs.

These models are part of SEMER cost estimating effort which comprises also investment, fuel and operating costs for PWRs.

SEMER (Système d'évaluation et de modélisation économique) enables estimating the economic impact of various nuclear reactors. Models for nearly all fossil energy based systems provide a basis for cost comparisons.

SEMER has been developed to support top management and project leaders with a simple tool for cost evaluations enabling a choice between competitive technological options.

The underlying principle of model development in SEMER is based on the observation that in most cases, especially in the preliminary phase of a given project, it is sufficient to first make a relative cost estimation by using the fastest and simplest available method. The results obtained are then further refined using more accurate information from the final phases of the project and, where possible, using the detailed models. This approach thus involves the following steps :

- Breakdown of the project or installation into several sub-systems, each of which is capable of fulfilling a given function.
- Choice of a generic model (a model used previously, or available from the literature) bearing a sufficient number of analogies with the project under evaluation
- Derivation of the model into a general mathematical expression of the type

$$C_i = A_i + (B_i \times P_i^n)$$

where, **A, B, n** are the so called adjustment coefficients and **P** is a power or capacity.

- Determination of the coefficients and validation of results by applying well known mathematical techniques to a large number of cases with variations of **P.**

Among the models developed are : the **global models** for a quick estimation of power plants, the **detailed models** for the cost calculations of PWR components, circuits and civil engineering, and the fuel cycle models for UOX and/or MOX fuelled nuclear reactors.

The models for PWRs are:

Account number	item	Model Used
21	Buildings and structures at the plant site	Specific model
	Excavation works	Ratios
22	Reactor plant equipment	Global model
	Reactor Vessel	Specific model
	Pressurizer	Specific model
	Steam generators	Specific model
	Nuclear Auxiliary Systems	Specific model
23	Turbine generator	Global model
24	Electrical equipment	Global model and ratio
	Diesel	Global model
25	Water intake and heat rejection system	Global model and ratio
26	Miscellaneous plant equipment	Ratio
27	Special materials	Ratio
28	Simulator	Data
	Direct costs	Global model

Here are some explanations on several models:

Account 21

<u>Civil works</u>

A well known base cost of a nuclear type building is taken : C_B. Cost estimate of a new building of a same type is C_B multiplied by an adjustment coefficient K_{AR} which is given by the formula :

$$K_{AR} = 2.5/30 \; [((Th1 + Th2)x(1+(FPRx0{,}6/Th1))/L)+((Th1 + Th2)x(1+(FPRx0{,}6/Th1))/B)+((Th1 + ThF)/(2H))]$$

Where Th1 is the width of the first concrete wall, Th2 the width of the external wall, if there is one (reactor building), ThF the width of the concrete foundation, FPR is a Factor for Partition in Rooms, L building length, B building base or width and H building height.

FPR value varies from 0,15 for simple buildings up to 1,5 for Nuclear Auxiliary Buildings with PWR 900 civil works model

This formula is based on characteristics representative of the compactness of the building walls.

The model, which essentially relies on the above formula, allows obtaining building costs per m^3 of inner building volume (which is a logical functional unit). Costs per m^3 of concrete of each building are easily deduced from cost of building divided by concrete volume.

For French PWRs, costs per m^3 of concrete range from 2000 to 3000 €.

<u>Excavation works</u>
Cost is obtained by ratios per m^3 of excavation, ratios dependent on the type of site.

<u>Account 21 global formula</u>
The following global formula summarizes cost for account 21 as a function of reactor power:

$$C_{M€\ code\ 21} = 8\ P^{0..5}$$

This is an empirical formula based on French PWRs cost data.

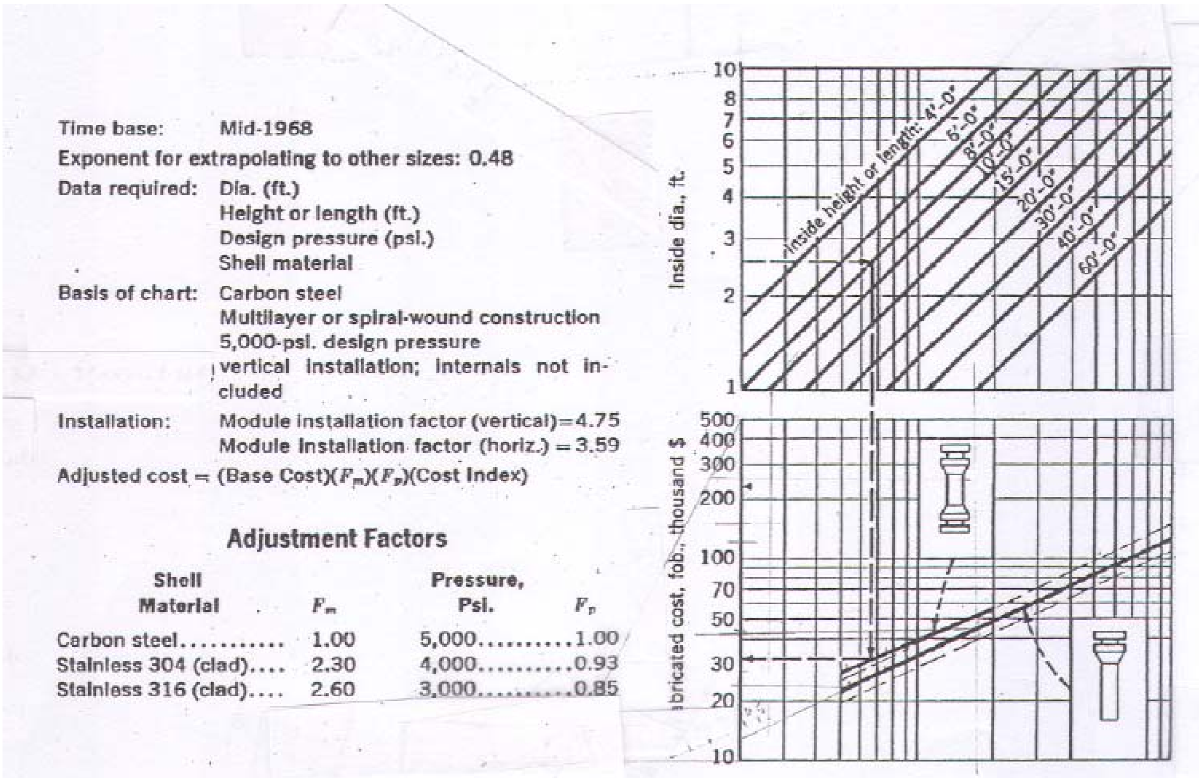
Account 22: Reactor plant equipment

<u>Primary Vessel</u>

The model estimates cost of one primary vessel and its appendices (flanges, piping, supports, for vessel fixation in concrete), its internals, control rods and internal supports)
This base cost model gives an estimation of cost of a vessel of given dimensions (height, diameter) as a function of pressure (by an adjustment factor) and material quality (factor depending of resistance required towards environmental conditions). This model deals with chemical industry vessels.
For nuclear vessels, other factors intervene, which account for inox coating, internal surfaces' finishing and of quality controls. These important factors (3.9 for inox coating and 1.8 for quality factor) are an upper limit.
The formula for the vessel cost is obtained by the following process:

<u>Pressurized vessel cost formula</u>

Cost construction is first based upon cost curves finely validated for industrial chemical vessels, given in the 1968 edition of Popper's handbook (Estimating the Cost of High Pressure Equipment by K. Guthrie). It starts by the costs of standard vessels of given dimensions at 5000 psi design pressure, to which are applied adjustment factors for pressure and material quality.
These curves and factors are given below:



COST OF MULTILAYER OR SPIRAL-WOUND PROCESS VESSELS designed to contain pressures of 3,000 to 5,000 psi—Fig. 2

This gives, in 2005 euros, the approximate formula for a common industrial pressure vessel:
Cost (M€) = $(D/2.2 + 12)^{1.8}(D/0.6)^{0.1}(H/3.5)^{0.5}(0.65 + 0.001\ p)$
For nuclear primary vessels, other factors intervene to account for stainless steel coating, polishing of internal surfaces and quality of controls. These high factors have been determined after validation of real cost data and discussion with vessel makers.

To the above formula is applied a factor of 1.8 for quality assurance and a factor of 3.9 for stainless steel coating.

Thus, Cost (M€) (of the vessel only) = $7\ (D/2.2 + 12)^{1.8}(D/0.6)^{0.1}(H/3.5)^{0.5}(0.65 + 0.001\ p)$
The model then calculates vessel mass by a simplified formula giving vessel width from pressure and acceptable metal stress, and then calculates mass through the geometric data (diameter, height, width).:
This gives a specific cost per kilo of vessel.
The model is applicable to all vessels under pressure of nuclear quality.

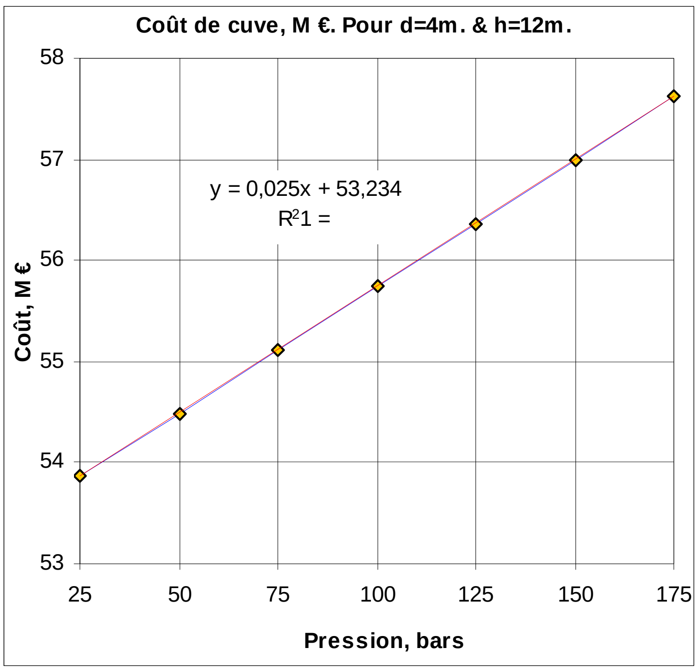
Vessel with its appendices and internals

Weight of appendices is multiplied by their mass, which gives a vessel cost FOB with appendices. Adding instrumentation, supports and transportation costs gives the total cost of the vessel installed, without internals.

Upper and down internals masses are calculated by their dimensions, and the cost per kilo of internals is based on the cost per kilo of vessel, on which a factor of 1.27 is added for quality assurance and a factor of 2.3 for stainless steel.
For the supports, their cost is the cost of internals multiplied by a factor validated by experience.

Total cost

Total cost of a nuclear primary vessel fully equipped with control rods is the cost with appendices and internals and the number of control rods multiplied by their unit cost.
From this, simplified formulae has been deduced, as a function of vessel internal volume and reactor power:
$C_{M€}$ vessel = 20 Volume (m^3) $^{0.25}$
$C_{M€}$ vessel = 20 Power (MWe) $^{0.25}$
(see figure below)



Pressurizer

There is a specific model for pressurizers of PWRs, which is summarized in one of the following formulae:

EQUATIONS of pressurizer cost (year 2002) =
According to plant power
C (M€.) = 0,5 * Power (MW (e)) ^ 0,5
According pressurizer volume
C (M€.) = 2,7 * Volume (m3) ^ 0,5

The basic formula is the same as the one for primary vessel, with lower factors because pressurizer vessel is less complex.

Steam generators
A specific model has been elaborated.

Nuclear auxiliary systems
Detailed models have been established with a good cost data base from PWRs for equipment and installation of various types of pressurized circuits (with bends, T-shaped, valves…), reservoirs, pumps, heat exchangers…

Account 22 global formula

The following global formula summarizes cost for account 22 as a function of reactor power:

$$C_{M€\ code\ 21} = 20(0.06\ P + 100)^{0.25}$$

What is important to note, for this global formula as for other COA global formulae, is that the cost given by the global formula is always higher than the sum of the costs of the equipments and systems, because small equipments are not accounted as well as site work on interfaces between the equipments and systems.

As an example, for a French PWR 900 MWe, the sum of specific equipments and systems represents 87 % of COA 22 total cost.

Account 23

Turbine generator

Cost figures for the turbo-alternator part of a gas turbine plant may be taken from (a cost model exists which is summarized by the formulae hereunder (for the whole plant):

Gas turbine plant cost C1 as compared with a reference C0/ P0

C1 = (0,1*Co)+((0,9*Co)*((P1/Po)^0,7))

Turbo-alternator part is about 3/5 of total direct costs of the plant.

Some complements are necessary for containment and heat exchange, and also

should be added 15 to 20 % for adaptation to nuclear environment.

H.1.2 Exponential size/rating cost factor

These simple methods use correlation of cost to size or rating of equipment, system, or complete plants. It gives cost as a function of design parameters, typically process unit capacity, rating, surface area, weight, diameter, or other physical data. The following sample exponent factors have been utilized for chemical and petrochemical industry projects.

PLANT	Rating **UM**	Cost **Exponent**
Generation plant		
Steam Turbine	kWe	0.50
Diesel Generators to 500Ton/min	kWe	0.62
Diesel Generators to 120Ton/min	kWe	0.72
Gas turbines	kWe	0.50
Combined cycle gas turbine	kWe	0.48
Chemical plants		
Acetone production plant	TON	0.45
Ethylene production plant	TON	0.83
Refinery plants		
Distillation plant	BPD	0.49
Refinery plant	BPD	0.81
Equipment		
Centrifugal pump and motor	HP	0.41
Compressors and motors	HP	0.83
Electric motors > 50kW	kW	0.77
Heat exchangers (over $100m^2$)	m^2	0.62
Tanks	m^3	0.63
River pumps and filtration plant	LPM	0.81
River pumps, filters and treatment plant	LPM	0.44
Refrigeration plant	Ton	0.72
Gas compressor and motor	HP	0.82
Piston pumps	HP	0.71
Horizontal vessel	m^3	0.60
Vertical vessel	m^3	0.65
Air receiver	m^3	0.73
Heat exchanger	m^2	0.65

H.1.3 Process equipment bulk factors

The basic principle is that for a similar system, the relationship of installation labor and bulk material costs are related to the cost of the process equipment. This cost estimating approach has been used in the chemical and petrochemical industries where continued development over several decades has produced simple, but powerful, methods for cost evaluations. Similar cost relationships can be established from reference power plant cost data for use on similar process systems.

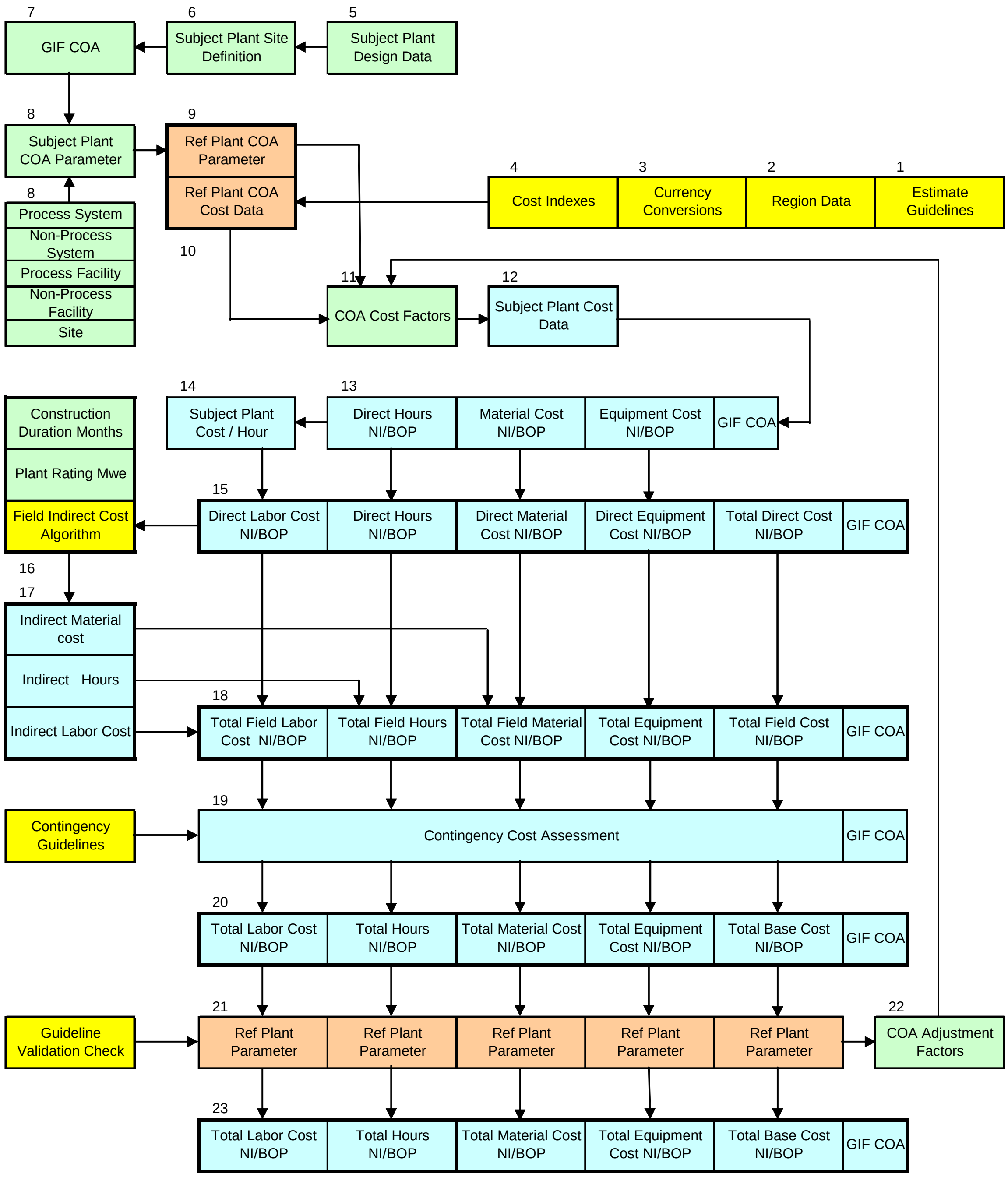
H.2 - Simplified top-down estimating process

A simplified top-down estimating process includes discrete steps that are depicted in Figure H.2.1 and described as follows. The item numbers correspond to the diagram below.

The first four items are general data sources that are of a more regional nature rather than specific to system design. The data is required for conversion and adjustment of reference plant cost data prior to development of subject plant cost estimates.

1. Guideline – Review these Estimating Guidelines for requirements in format, content and methodology.
2. Guideline – Determine Regional cost data, productivity factors, pricing levels, cost indexes, currency conversion factors, and other regional information.
3. Guideline – Establish currency conversion factors for all regions.
4. Guideline – Establish cost indexes for all regions for adjustment of reference plant costs to nominal cost date.
5. Subject plant data – Review the subject plant design and establish all major parameters for establishing cost relationships with reference plants, for example plant rating MWe, building areas and volumes, system data, heat balance, etc.
6. Subject plant data – Review the subject plant site specific scope and establish parameters for defining the subject plant site specific costs.
7. Subject plant data – Review the subject plant scope to the GIF COA to ensure a complete project cost definition, inclusive of areas that may not be defined at the time of cost development.
8. Subject plant data – Segregate subject plant scope to cost elements that can be related to reference plant data. These cost elements may be at summary COA levels for components, systems, or complete facilities for portions of the plant that are readily relatable to reference plant data. For unique and specific design features associated with the subject plant, the scope may need to be developed to a more detailed level to support cost development, even with a top-down approach. Quantify the major plant parameter that relates to the scope of the desired cost element. The parameter may be: total plant rating MWe; system capacity in Btu or GPM, pressure or temperature; physical characteristics such as weight, liters or cubic meters: other suitable parameter.
9. Reference plant data – Select a reference plant that contains the required cost element with corresponding plant parameter data.
10. Reference plant data – Adjust the reference plant cost data for the required pricing levels, productivity levels, and cost component separation, including GIF COA. Extract the reference plant costs for the scope of the cost element and quantify the same parameter associated with the cost element.
11. Reference plant data – Establish a ratio of the parameter for subject plant to reference plant. Using guideline cost exponents that are appropriate to the cost element, calculate the cost adjustment factor.
12. Subject plant calculation - Apply the cost adjustment factor to the reference plant cost details to calculate the equivalent costs for the subject plant. Each cost element should consist of equipment cost, material cost, and construction labor hours if possible. This level of detail is required to support other top-down estimating techniques for cost elements, such as field indirect costs, manpower levels, or scheduling considerations. Different reference plants can be used for various cost elements of the subject plant provided they are adjusted to the common GIF COA, regional influence, pricing, and productivity levels.
13. Subject plant calculation – Summarize all the cost elements to level three and two of the GIF COA.

Figure H.2.1 Schematic diagram of simplified top-down estimating process



Yellow = Guideline data, Orange = Reference plant data, Green = Subject plant data,
Blue = Subject plant calculations

The following steps require reference plant cost data to be available with separated labor cost and hours at an appropriate COA summary level.

14. Subject plant calculation – Develop composite labor cost per hour inclusive of all benefits, including fringe benefits, travel, and living costs. The labor cost per hour is usually calculated for the planned workweek by craft for journeyman, apprentice, and foreman, then applied for a craft crew and extended by craft mix percentages for a category of work (i.e. civil, mechanical, electrical, etc.), or total direct cost level if an average craft mix is used for direct costs.
15. Subject plant calculation – The subject plant direct labor hours, derived from the reference plant cost data, are extended by the appropriate cost per hour to estimate the labor cost component, and added to the equipment cost and material costs to calculate the subject plant total direct cost.
16. Guideline – Field indirect costs can be calculated with algorithms that relate the size of plant and duration of the construction period relative to the direct craft labor cost (See section 5.3.5).
17. Subject plant calculation – Field indirect costs consist of three components that are related to:
18. one time charges, such as temporary facilities purchased and erected at start of construction;
19. schedule duration related costs, such as equipment rentals and site cleanup; and
20. direct construction related, such as tools and consumables.
21. Suitable algorithms can be used to calculate the field indirect costs and hours. The resultant craft hours together with the planned construction schedules provide basis for development of manpower levels and staffing curves.
22. Subject plant calculation – The summary of Direct Cost and Field Indirect Costs produce Total Field Cost. This provides the baseline cost data for calculation of Design and Project Management / Construction Management (PM/CM) Services.
23. Guideline – A contingency assessment is performed for the subject plant estimated costs to derive the appropriate contingency costs for each summary account code level. See Appendix A.
24. Subject plant calculation – The subject plant costs are summarized to appropriate levels of GIF COA.
25. Guideline – Several validation checks can be performed to compare the subject plant cost estimate relative to cost parameters derived from reference plants cost data. Parameters such as indirect cost percentage of direct cost, services percentage of field costs, cost per kWe, direct equipment percentage of total direct cost, direct labor cost of total direct cost, direct labor hours, and material cost per monetary unit value (e.g., US$ 1000) of equipment cost, etc.
26. Subject plant calculation – The results of the validation process provide adjustments that are recycled to the cost factors in step 11, until the results are validated relative to established parameters for reference plant cost data.
27. Subject plant calculation – The summary is Base Cost before calculation of other capitalized costs and Total Overnight Cost.
28. Subject plant calculation – A summary at level 2 COA provides input to other cost models for calculation of LUEC.