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COST ESTIMATING GUIDELINES FOR GENERATION IV NUCLEAR ENERGY SYSTEMS

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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)

- 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 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) and cost-estimating guidelines 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, G4-ECONS, accompany this document. The combination of the software and guidelines 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.

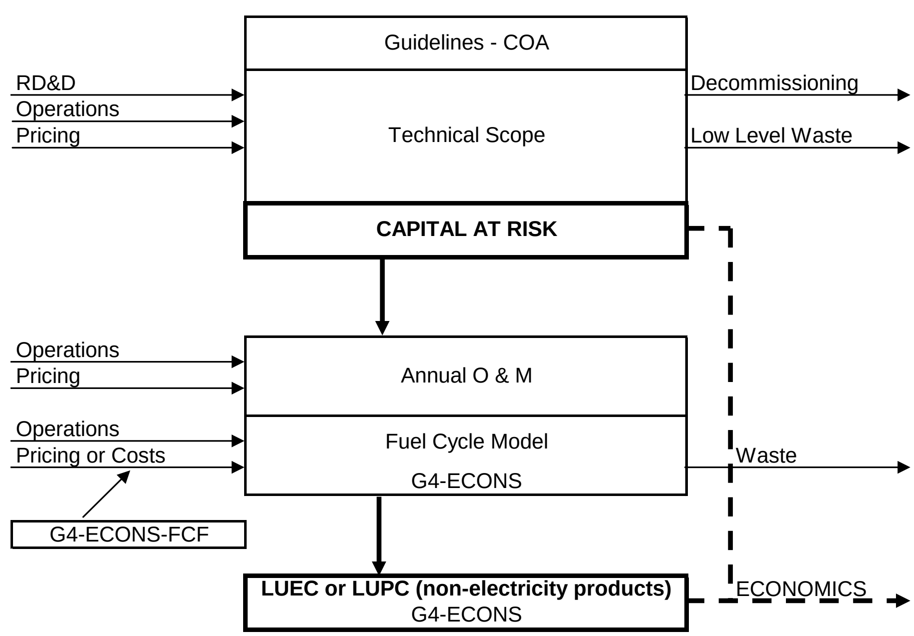
The levelized unit of energy cost (LUEC) that is evaluated includes design, construction, commissioning, operations and maintenance, fuel cycle, and decommissioning costs for the first-of-a-kind (FOAK) through Nth-of-a-kind (NOAK) commercial nuclear units. System development teams (System Steering Committees) are expected to 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

In March 2003, the U.S. Department of Energy (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 deploy new, safe, economical, and reliable nuclear energy systems before the year 2030. The GIF established an Economic Modeling Working Group (EMWG) in 2003 to create economic models and guidelines to facilitate future evaluation of the Generation IV nuclear energy systems and assess progress toward the GIF economic goals.

This document describes the structure of an integrated economic model for Generation IV nuclear energy systems. It is accompanied by the G4-ECONS software (GIF/EMWG, 2006) implementing the guidelines and models. These tools will integrate 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 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.

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



The model has four parts: construction/production, fuel cycle, energy products, and modularization. The construction/production and fuel costs parts of the model are described in some detail in this document, as their design, programming, and integration were the early focus of the EMWG program. The energy product part is discussed in Chapter 9. Modular production considerations are discussed in Chapter 11. The integrated model also incorporates a standard Code of Accounts and a cost estimating methodology.

Standard Code of Accounts

The life cycle of any nuclear system, including those considered by the 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 additional insight into the technical and business issues associated with each concept. Subdividing costs in a common manner for all concepts allows for relevant comparisons. This commonality may be accomplished by using a uniform Code of Accounts (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 Nuclear Utilities Services (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 COA, described in Section 1.5. It is sometimes referred to as the “two-digit” level (i.e., costs are summarized at the level of major subsystems). The EMWG created a separate COA for RD&D costs (Chapter 3).

Cost Estimation Methodology

Two approaches to cost estimation 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 Appendix H

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 account for all construction commodities, plant equipment, and labor hours.

Chapter 4 provides general guidelines and assumptions applicable to both approaches.

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 (SFR), are likely to have their estimates prepared at a high level of detail. Estimators should use the standard cost-estimating categories and the GIF COA (at least at the two-digit level) for both methods.

Construction/Production Model

Cost estimates prepared by system design teams should 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 COA described in Section 1.5, prepared by the methods outlined in 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 decontamination 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 Oak Ridge National Laboratory (ORNL) nuclear energy plant databases (NECDB) and reports (Delene and Hudson, 1993; and ORNL, 1988c), to calculate these costs.

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 uranium or plutonium, and, for uranium, the transaction tails assay assumed by the enrichment service provider. The EMWG model uses algorithms similar to those described in NEA (1994) to estimate 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 that use commercially available fuels can be found in NEA reports (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.

Chapter 8 of the guidelines addresses 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 SFR system might require innovative pyrometallurgical and pyrochemical facilities for fuel fabrication, reprocessing, and re-fabrication. For such systems, price data for fuel cycle services generally are not readily available. Therefore, a unit cost of fuel cycle services, such as $/kgHM for fuel fabrication, should be calculated using a methodology similar to that used for LUEC calculation for the reactor system. 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 Chapters 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 generation, 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 discussed in Chapter 11.

Note to the Reader

The G4-ECONS 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 may be necessary for the EMWG to work with them to ensure that these *Cost Estimating Guidelines* meet their needs, as well as those of the program decision makers.

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1. INTRODUCTION

In March 2003, the U.S. Department of Energy (USDOE) 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 deploy new, safe, economical, and reliable nuclear energy systems 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.

The GIF established an Economic Modeling Working Group (EMWG) in 2003 to create economic models and guidelines to facilitate future evaluation 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. Accompanying software, G4Econs, used in conjunction with these guidelines, facilitates consistent, comprehensible cost estimates to evaluate the Generation IV nuclear energy systems with respect to the established economic goals.

1.1 Purpose of Cost Estimating Guidelines

The economic goals of Generation IV nuclear energy systems, as adopted by the 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 because their characteristics differ significantly from those of current Generation II and III nuclear energy plants. The Generation IV EMWG has undertaken a multi-year task to develop such a comprehensive model to support GIF objectives. If such a model is to realistically compare among the different reactor technologies/systems and provide a consistent basis for economic evaluation, ideally the base assumptions and data underlying the model must be applied consistently to all systems. This desired goal is 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 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 report provides the information necessary for the system design teams to estimate costs using the software.

The system development teams for the various concepts will likely 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).

Each team will likely begin the development of a "baseline" reactor system concept at a "pre-conceptual" level. Given sufficient funding, most teams may have enough information, with some data possibly generated by architect/engineer (A/E) subcontractors, to aid in the design and cost estimating process. Some teams may not have reached this goal because of lack of funding support from their international sponsors. Because the six reactor systems are at different stages of research, development, and demonstration (RD&D), the knowledge to prepare comparable cost estimates varies widely among systems and among nations.

This fact makes early imposition of a consistent cost-estimating methodology difficult but not insurmountable. Certain cost-estimating organizational concepts, inputs, and assumptions can be applied to all six concepts to 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)

A methodology to determine 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 such 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 guidelines are accompanied by the G4-ECONS software that implements the models and major assumptions.

Creating guidelines early in the GIF 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 (COA) 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 process that integrates cost estimation with design development.)

To realize these advantages, this document addresses the cost estimation process as well as cost-estimating guidelines. These guidelines extend previous costing methods and approaches to address

Generation IV systems; however, these 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 Oak Ridge National Laboratory (ORNL) in 1993 to support the non-commercial 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 two “advanced” reactor technologies were being funded at that time by USDOE’s Office of Nuclear Energy. (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.

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 and commodity prices. As Table 1.1 shows, the evaluation scope is much broader for GIF concepts than for the 1993 evaluations in the technical scope, product streams, and 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 highly enriched uranium MHTGR; closed for uranium/plutonium LMR	Two once-through systems, four closed-cycle systems with partial or full recycle
Main products	Electricity	Electricity, hydrogen, desalination, and actinide management
Reactor and balance of plant (BOP) fabrication concepts	Onsite 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 onsite 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 three- or four-digit level (bottom-up estimates)	None to pre-conceptual analysis; reference EEDB data available for similar reactors: MHTGR, LMR, LWR; top-down estimating required for some concepts.
Fuel cycle material and service costs	Most materials and services available commercially; both reactor types required	For most systems, fuel cycle costs need development for new fuel cycle steps and processes; waste costs to

Attribute	1993 Cost Estimating Guidelines	Generation IV Cost Estimating Guidelines
	fuel fab/refab facility; waste disposal costs included.	be included; required regional or onsite fuel cycle facilities need pre-conceptual design and cost information.
First commercial plant deployment date	2000	Target 2030 and beyond

Therefore, wherever possible, the modeling system and associated guidelines for economic data input had to be sufficiently generic, inclusive, and robust as to bound all possible cases that may require examination. In some areas, simplifications could 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. However, in other areas such as labor productivity and wage rates, new non-U.S. data are needed, which may be difficult to obtain.

The EMWG decided to use 5% and 10% real (i.e., excluding inflation) discount rates because these rates bracket the 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 onsite 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 to be prepared for these onsite 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 onsite construction of most systems.

Finally, the EMWG guidelines do not model unit costs for competing technologies, such as fossil or renewable generation facilities, or conventional fossil-fuel-based hydrogen production facilities. For electrical generation, recent reports 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 Organisation for Economic Cooperation and Development (OECD) study (IEA and NEA, 1998).

1.3 Relationship Between the EWMG Guidelines and the Overall EMWG Modeling Effort

The EMWG modeling effort upgrades existing nuclear-economic models (component models such as capital, operation and fuel cycle) and develops new ones where needed. The models address each of the following four economic areas: construction/production cost, nuclear fuel cycle, 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). The Integrated Nuclear Energy Economic Model combines these models to 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 the following:

Systems at the deployment stage are assumed to be 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 Nth-of-a-kind (NOAK) plant is assumed to be built such that its cost and schedule variations can be compared to the first-of-a-kind (FOAK) plant (see Appendix E).

A pre-approved – licensed – site is assumed to exist for plant construction.

The finance and business model assumes 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.

These guidelines foster consistent comparisons among the advanced reactor technologies under consideration. The costs obtained using the guidelines are intended to be reasonable estimates that bound 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 provide the background to understand the EMWG guidelines. Note that some of these terms will not be used or applicable until much later in the nuclear energy system development and deployment cycle.

Balance of plant (BOP): All areas of the plant and systems not included in the nuclear island scope.

Base construction cost (BCC): The most likely plant construction cost based on direct and indirect costs only. This cost is lower than the total capital investment cost (TCIC) because cost elements such as owner's cost, supplementary cost, and financial cost are not included. Direct costs are those costs directly associated on 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 such as field indirect costs, design services, engineering services, 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.

Base cost: The initial costs developed for the subject plant before validation and any subsequent cost adjustments.

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

Bottom-up estimate: A cost estimate derived from detailed design and pricing information.

Category: The grouping of commodities 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 included in a category of work. This composite cost per hour simplifies the estimating process and is based on actual construction experience for the crafts involved in each category of work

COA detail: A summary of plant components common to a system, facility, or function.

Commodity: A component detail of a category. For example, the concrete category might consist of the commodities formwork, rebar, embeds, and structural concrete.

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

Constant money: The cost for an item measured in money with the general purchasing power as of some reference date. Because inflation is associated with the erosion of the purchasing power of money, constant money analysis factors out inflation. The EMWG guidelines only consider constant money costs (see also “real cost of money”).

Construction module: A free-standing, transportable pre-assembly of a major portion of the plant, a complete system, subsystem of the unit or elements of all the systems in a given location in the plant. For example, 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, a construction module 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: Field non-manual personnel such as superintendents and field engineers engaged in direct supervision of construction activities.

Contingency: An adder to account for uncertainty in the cost estimate (see Section 7.3 and Appendix A). Contingency includes an allowance for indeterminate elements and should be related to the level of design, degree of technological advancement, 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. A contingency can be also applied to the interest during construction and the capacity factor to account for uncertainty in the reactor design/construction schedule and reactor performance, respectively.

Cost component: Usually a COA detail component, such as reactor vessel in a nuclear steam supply COA that includes cost elements for equipment, labor, and materials.

Cost element: Cost details separated into equipment, labor, or materials.

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

Cost factor exponent: Consideration of "size benefit" or common costs reflected in the cost of similar equipment, facilities, or systems with different ratings, capacity, or some other suitable parameter. It is usually applied against the ratio of parameter values.

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

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

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

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

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

Design services: Services performed offsite or onsite to produce all design documents and calculations required to construct the plant. For a standard pre-licensed plant with certified design, the services are limited to those required to adapt 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 including salaries, office space, office furniture, office equipment, supplies, communications, travel, and other labor-related costs. Fees for the services are included in another account.

Direct cost: All costs to construct a permanent plant, excluding support services such as field indirect costs, construction supervision, and other indirect costs (see also "base construction cost").

Direct labor: Crafts involved with construction activities of a permanent plant, rather than general support activities such as site cleanup. Direct labor includes truck and crane drivers delivering equipment to permanent locations and all work operations associated with the permanent plant, such as equipment maintenance or construction testing before plant startup.

Discount rate: In the context of the GIF guidelines, the discount rate is equal to the real cost of money. Comparison calculations should 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. The default value adopted in the Integrated Nuclear Energy Economic Model 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 estimates, it is assumed to be zero, unless otherwise justified. Cost estimators should adjust reference plant costs expressed in values before the January 2001 pricing basis by appropriate indices. See also Table G.1.11 for escalation adjustment factors.

Equipment: 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 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 is categorized as an equipment cost. Non-process-related equipment such as HVAC, plumbing, lifting or maintenance equipment, large pipe and valves, electrical equipment, and control equipment is classified as a material cost.

Equipment module: 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. Types include box, equipment, structural, connection, electrical, control system, and dressed equipment modules. These modules are applicable to both the nuclear island and BOP, including support buildings. The same definition applies to equipment modules in fuel cycle, end-use, or factory facilities.

Factory (manufacturing facility) FOAK costs: The development of manufacturing specifications, factory equipment, facilities, startup, tooling, and setup of factories used for manufacturing specific equipment for the nuclear energy system. These costs can be minimized if existing facilities are used for module production; these facilities might not be dedicated or even have production as their primary use (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 reflected in the unit/plant costs, and as such, estimators should amortize the price 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, the price of the modules is assumed to include a fair share of any factory operating and capital recovery costs (overheads).

Figure of merit: A particular type of calculated cost (e.g., LUEC) of high interest to decision makers because it can allow comparisons among various designs or allow optimization of a specific design.

First commercial plant costs: The first standard plant of a particular type 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, are 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 at the end of the definitions).

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

FOAK plant costs: Costs necessary to put a first commercial plant in place; these will not be incurred for subsequent plants. Design and design certification costs are examples of such costs (see Figure 1.1 at the end of the definitions).

Force account: 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: All costs not directly associated with a specific permanent plant, such as field indirect, construction supervision, design services, and PM/CM services (see also “base construction cost”).

Indirect labor: Construction craft labor involved in performing support activities not directly associated with a permanent plant. Indirect labor includes temporary facilities, temporary services, warehousing, construction equipment maintenance, and security services, among others.

Industrial-grade construction: Construction practices that conform to generally accepted commercial requirements, such as those for fossil-fired plant construction. Industrial-grade construction could be used for end-use facilities such as a hydrogen production plant. A module factory could also use industrial-grade construction for the production of some modules (see also “nuclear-safety-grade”).

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 GIF guidelines, the initial core costs are considered part of the total capital investment that is amortized in the capital component of the LUEC. The fuel cycle algorithms discussed in Chapter 8 are used to calculate the initial core costs.

Interest during construction (IDC): 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: The nuclear island or turbine island consisting of multiple related buildings or facilities. For example, the nuclear island might comprise a reactor building, containment, fuel-handling facilities, and others.

Large monolithic plant: An energy plant consisting of a large nuclear steam supply system (NSSS) with 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 of today’s pressurized-water reactors (PWRs) and boiling-water reactors (BWRs) are considered monolithic plants.

Levelized Unit of Energy Cost (LUEC): For a standard plant, the 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, possibly including revenue offsets from byproduct production. Typically the four reported components of LUEC are (1) the capital component (recovery of capital cost over economic life); (2) the production or non-fuel operations and maintenance component; (3) the fuel component; and (4) the decontamination and decommissioning (D&D) component. Chapter 9 discusses the calculation of LUEC. Normally this cost does not include RD&D costs. 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: Field-purchased (site material) and/or bulk commodity items such as lumber, concrete, structural steel, and plumbing items. All piping, wire and cable, and raceways are material items, including those in building service power systems. Also included is non-process-related equipment such as heating, ventilation, and air conditioning (HVAC); cranes; hoists; doors; plumbing; sewage treatment; and electrical and control equipment. To facilitate top-down estimating techniques, only process-related equipment is classified as equipment cost.

Modularity effect: 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 or stick-built plant to facilitate factory fabrication of modules for shipment and installation in the field as complete assemblies.

Modular unit: A nuclear unit assembled onsite from factory produced modules, usually of smaller capacity than a monolithic unit, to maximize the benefit from modularity effects.

Module: Usually a packaged, fully functional assembly for use with other standardized assemblies to obtain a system. See also “construction module” and “equipment module.”

Monolithic plant: A plant constructed in the field without extensive use of modules; also referred to as a stick-built plant.

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

Nominal cost of money: 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.

Nominal currency/dollars: The reference currency (adopted by default in the GIF guidelines as the U.S. 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.

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

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

Nuclear island (NI): The part of a plant containing the majority of nuclear-related equipment and systems. Typically it consists of containment, the reactor building, the fuel handling building, and similar facilities.

Nuclear-safety-grade: Construction practices that satisfy the quality assurance and other requirements of national licensing (e.g., 10 CFR 50, Appendix B, in the U.S.). Both reactor and fuel-cycle facilities will require some nuclear-safety-grade construction.

Overnight cost (OC): 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 in the GIF guidelines, which is not usually the case for conventional reactor estimates. This expanded definition reflects 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 before calculation of the IDC simplifies the algorithms used to calculate the LUEC.

Owner's cost: Cost components that are typically the owner's responsibility such as capitalized operations, capitalized supplementary costs, and capitalized financial costs.

Owner's discretionary items: For a power plant, 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 the owner's cost for a specific project.

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

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

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

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

Productivity: 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 by the standard unit hours for the work. Usually it is expressed by category of work, such as concrete, piping, or electrical. It can also be calculated for total direct, indirect, or craft labor as well as craft supervision or total field non-manual personnel.

Project management/construction management (PM/CM) services: Services performed onsite or offsite to manage the total project. Such services include project manager and staff, procurement buyers and contract administration, project cost engineers, project schedulers, first aid, medical, administrative, payroll, accounting, clerical, labor relations, and security, as well as salaries, salary-related costs, office equipment, supplies, and fees for the services.

Prototype costs: Costs specific to any prototype plant. These costs include those for 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 in the certification process 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.

Reactor module: 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 a site as a prefabricated component, without necessarily requiring additional construction (see also "equipment module").

Real cost of money (r): 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 is needed to cover inflation. For consistent comparisons, costs estimated with the GIF guidelines use two rates: 5% and 10%.

Reference plant: A collection of information, including 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 are used to develop costs for a plant component or COA detail.

Reference plant costs: The basis for estimating baseline plant costs in the absence of a fully developed (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 5 on top-down cost estimation using reference plant costs).

Research, development, and demonstration (RD&D) costs: Costs associated with materials, components, systems, processes, and fuel development and testing performed specifically for the particular advanced concept. These costs are often borne by governments or industry consortia and are recovered depending on national practices. In the GIF 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" for other non-standard costs and Figure 1.1 at the end of the definitions).

Single-unit plant: A stand-alone commercial energy plant consisting of a single unit and all necessary common plant facilities. 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: The design and engineering of facilities 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. Cost estimators amortize these costs 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 costs for the first commercial standard plant and do not include the site-specific engineering costs 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 to obtain a license. In the U.S., it includes the design and analysis of prototype tests necessary for certification, coordination with the U.S. Nuclear Regulatory Commission (USNRC), and preparation of documents required to certify the standard plant design. These are FOAK non-recurring costs for the first commercial standard plant and do not include the site-specific engineering costs associated with all standard plants.

Standard unit hours: A set of unit hour rates per quantity of work scope. These rates usually serve as a basis to calculate standard hours for a project before applying a productivity factor for a specific project or site.

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

Stick-built plant: A plant constructed in the field without extensive use of modularization; essentially historic and current construction experience.

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

System designer: The organization performing the design of the specific type of plant.

Technology development costs: See "research, development, and demonstration (RD&D) costs."

Top-down estimate: A cost estimate derived from reference plant information rather than detailed design and pricing information.

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

Transition period: The period from the start of the construction of the FOAK plant 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 (second commercial plant [2OAK], third commercial plant [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).

Unit: A set of facilities and systems to produce electrical energy and/or other products such as hydrogen or desalinated water or production systems such as reactor or turbine generator systems (see also "single-unit plant").

Unit equipment cost: Total costs associated with a piece of process equipment. The costs usually include costs for vendor engineering, testing, certification, packaging for shipment, local delivery, warranty, and recommended construction spare parts.

Unit hours: Sum of all construction craft time spent to install equipment or commodities 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, unit material cost 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 research, development, demonstration, deployment, and standard plant costs

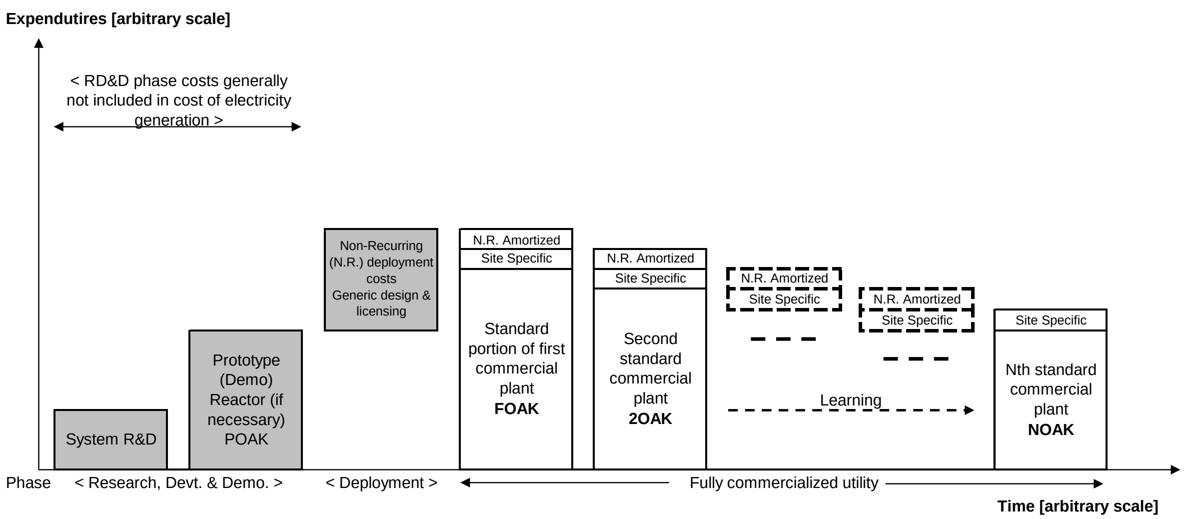

Figure 1.1 shows the relationship in time between some of the cost categories and which costs are included in the cost of electricity. Note that the horizontal and vertical scales in the figure are illustrative only and not scaled to real time or expenditures.

1.5 The GIF Code of Account (COA)

The International Atomic Energy Agency (IAEA) has developed a comprehensive account system capable of addressing a spectrum of capital, fuel cycle, and operations and maintenance costs, from a complete nuclear energy plant down to individual systems and components. Because 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. The IAEA created this account system 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). 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 are included in summary level accounts in the GIF COA.

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 (two-digit) level. As in the original ORNL/United Engineering EEDB (ORNL, 1988a, 1988b, 1988c), direct costs include equipment, direct installation labor-hours, and commodities for installation such as wire and concrete. (Note that the GIF guidelines present COA below the two-digit level, particularly in Appendix F. This additional detail is meant to assist the development teams in estimating detailed costs using the bottom up method. For reporting cost estimates, the EMWG advocates only a two-digit COA to protect proprietary information.)

The following subsections describe the GIF COA for nuclear energy plant capital investment, nuclear fuel cycle accounting, and operations and maintenance accounting.

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 startup 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 TCIC is the cost of building the plant and bringing it into commercial operation. The high level categories adopted in these guidelines are as follows:

Account 10 – Capitalized Pre-Construction Costs
<u>Accounts 20– Capitalized Direct Costs</u>
Direct Cost

<u>Accounts 31-34 Field Indirect Costs</u>
Total Field Cost

Accounts <u>35-39 Capitalized Field Management Costs</u>
Base Construction Cost

Accounts 40 – Capitalized Owner Operations
<u>Accounts 50 – Capitalized Supplementary Costs</u>
Overnight Construction Cost

<u>Accounts 60 – Capitalized Financial Costs</u>
Total Capital Investment Cost

The GIF COA 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 provide costs for all accounts. The GIF COA is primarily a system of cost accounts based on a physical subdivision of the project. However, as a project matures, the COA may also be conveniently used for other purposes, such as filing, drawing and document control, and numbering and coding of equipment. The advantage of this COA is that it eliminates the need to develop separate systems; only one system needs to be learned, providing a common language for the whole project. At the 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 6 considers definitions at the three-digit level for use in bottom-up estimating. In the GIF TCIC account system (Table 1.2), pre-construction costs are allocated to Accounts 10, direct costs to Accounts 20, and capitalized indirect services to Accounts 30. The totals of these Accounts 10 through 30 represent base construction costs of the plant. Capitalized owner's costs are allocated to Accounts 40, and supplementary costs to Accounts 50. The subtotal at this level (Accounts 10 through 50) represents the plant overnight construction costs. Remaining capitalized costs for financing are allocated to Accounts 60 for a TCIC.

Table 1.2 Generation IV International Forum nuclear energy plant Code of Accounts

Account Number	Account Title
1	Capitalized Pre-Construction Costs
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
19	Contingency on Pre-Construction Costs
2	Capitalized Direct Costs
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 on Direct Costs
Direct Cost	
3	Capitalized Indirect Services Costs
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 on Indirect Services
Base Construction Cost	

Account Number	Account Title
4	Capitalized Owner's Costs
41	Staff Recruitment and Training
42	Staff Housing
43	Staff Salary-Related Costs
44	Other Owner's Capitalized Costs
49	Contingency on Owner's Costs
5	Capitalized Supplementary Costs
51	Shipping and Transportation Costs
52	Spare Parts
53	Taxes
54	Insurance
55	Initial Fuel Core Load
58	Decommissioning Costs
59	Contingency on Supplementary Costs
Overnight Construction Cost	
6	Capitalized Financial Costs
61	Escalation
62	Fees
63	Interest During Construction
69	Contingency on Financial Costs
Total Capital Investment Cost	

As shown in Table 1.2, the GIF COA includes several modifications from previous COAs:

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.

Accounts 22 through 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 for 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 through 39. (Under the old EEDB system of accounts, some of this was in the "90" series.)

Engineering and design work performed by the supplier and/or A/E at the home office(s) should be considered under Account 30.

Installation and construction labor for a particular subsystem should be included in the account for that subsystem, such as including installation and construction labor in Account 22 (reactor plant equipment) rather than in the IAEA Accounts 35 or 36 (where all labor for all subsystems is collected). This allows for better insight 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 COA.

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, and any credits realized through the sale and use of uranium, plutonium, heavy water, or other materials. Note that it may be necessary to revise this accounting system for innovative fuel cycles not considered by IAEA when its code was prepared.

Table 1.3 outlines the GIF COA used to summarize the nuclear fuel cycle costs for light-water reactors (LWR) 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 operations and maintenance costs.

Table 1.3 Structure of the Generation IV International Forum nuclear fuel cycle Code of Accounts

Account Number	Account Title
551	Fuel Assembly Supply, First Core
5512	First Core Conversion
5513	First Core Enrichment
5514	First Core Fuel Assembly Fabrication
5515	First Core Supply of Other Fissionable Materials (e.g., plutonium)
552	Services, First Core
5521	Fuel Management (U, Pu, Th)
5522	Fuel Management Schedule
5523	Licensing Assistance
5524	Preparation of Computer Programs
5525	Quality Assurance
5526	Fuel Assembly Inspection
5527	Fuel Assembly Intermediate Storage
5528	Information for the Use of Third-Party Fuel
84	Fuel Assembly Supply for Reloads
841	Uranium Supply for Reloads
842	Conversion for Reloads
843	Enrichment for Reloads
844	Fuel Assembly Fabrication for Reloads
845	Supply of Other Fissionable Materials for Reloads
81	Services, Reloads
811	Fuel Management
812	Fuel Management, Schedule
813	Licensing Assistance
814	Preparation of Computer Programs
815	Quality Assurance
816	Fuel Assembly Inspection
817	Fuel Assembly Intermediate Storage
818	Information for the Use of Third-Party Fuel
86	Reprocessing of Irradiated Fuel Assemblies
861	Credits for Uranium, Plutonium and Other Materials
862	Final Disposal of Fuel Assemblies
863	Final Waste Disposal
27	Heavy-Water Supply, First Charge
271	Heavy-Water Services, First Charge
87	Heavy-Water Supply, Replacement Quantities
871	Heavy-Water Services, Replacement Quantities

1.5.3 Operations and Maintenance Cost Account System

The operations and maintenance (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 outlines the GIF O&M cost account system. Note that all O&M costs are annualized.

Table 1.4 Structure of the Generation IV International Forum operations and maintenance Code of Accounts

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

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

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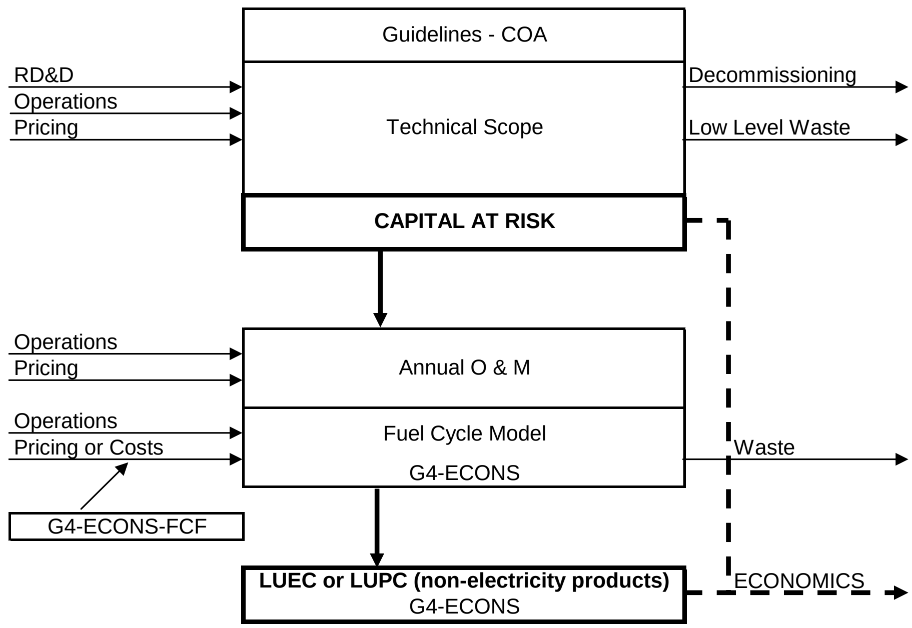
2. STRUCTURE OF AN INTEGRATED NUCLEAR ENERGY ECONOMIC MODEL

2.1 Flow Diagram for an Integrated Nuclear Energy Economic Model

The GIF COA is built from an Integrated Nuclear Energy Economic Model. Figure 2.1 shows the overall structure of the model created by the EMWG.

Figure 2.1 Structure of the integrated nuclear energy economic model



The model has four parts: construction/production, fuel cycle, energy products, and modularization. Figure 2.2 shows the structure of the model to calculate the construction/production costs. Figure 2.3 shows the structure and logic of the fuel cycle portion of the model. Chapter 8 discusses the fuel cycle in detail. Chapter 9 discusses calculation of energy production, and Chapter 11 discusses modularization.

Note that contingency is partitioned into three parts when calculating the LUEC. The first contingency is typically 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 applied to cover uncertainty in plant performance as measured by the capacity factor. Because unit cost is being calculated, this term covers the uncertainty in the denominator of the $/MWe figure of merit.

The remainder of this chapter describes how top-down and bottom-up cost estimating, the integration of cost estimating into the design process, and figures of merit relate to this model.

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

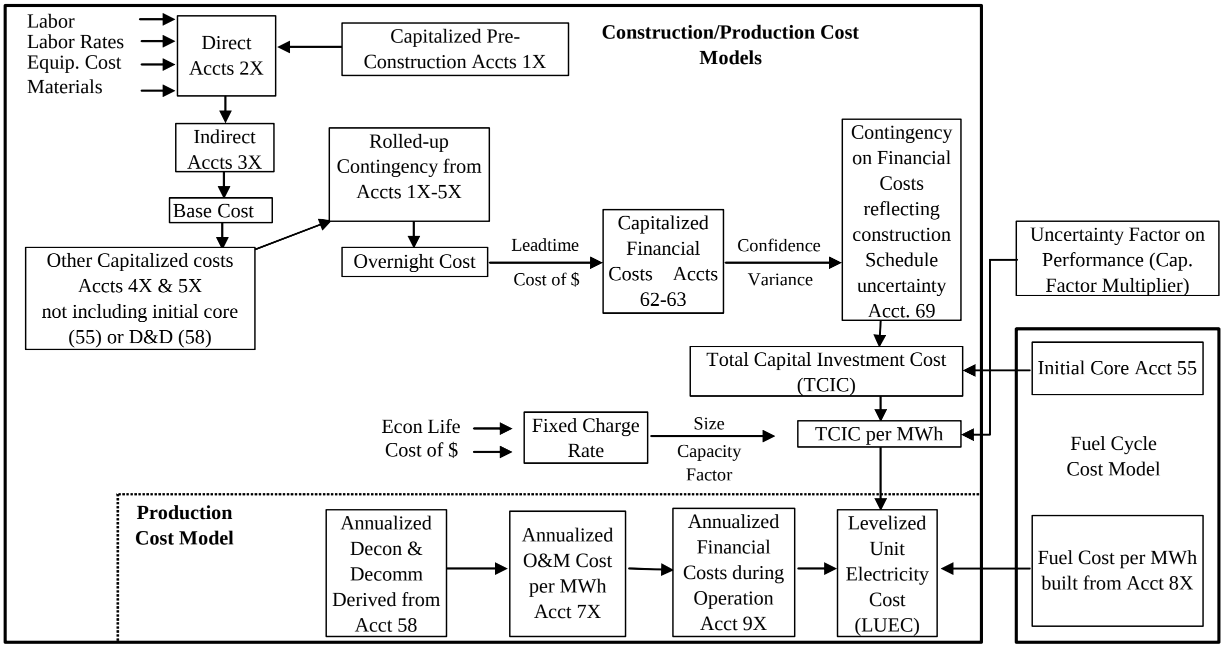
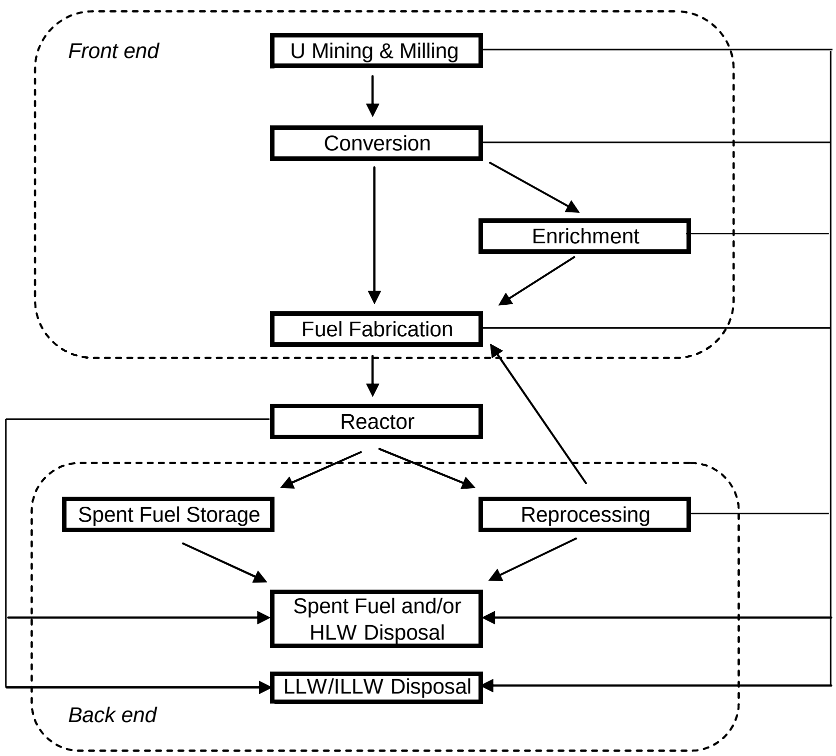


Figure 2.3 Structure and logic of the uranium-based fuel cycle part of the model



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 on the EMWG guidelines. They must be supported 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, 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 contains very detailed items, such as equipment lists, commodity quantity estimates based on drawings or direct from conceptual three-dimensional design models. Unit prices and unit labor-hour rates are then applied to the estimated quantities, extended, and summarized to the COA for the direct cost elements. Project execution plans provide the basis for detailed 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 detailed items and activities are then organized into a COA at least to the three- or four-digit level for all categories. Activities are often subdivided into a Work Breakdown Structure (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 model, the highly detailed three- to six-digit COA entries must be summed to the two-digit level. Other estimates, such as those for operations, would require similar summations 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). As expected, this method must be supported by data such as unit costs of labor, commodities, installation rates, construction labor-hour estimates, and siting requirements. Appendix G 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. Many of the Generation IV systems will likely use these methods because 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 increasing or decreasing the scale of the system or equipment. As an example, one might start cost estimating on the VHTR by scaling reactor plant equipment from a project for which detailed estimates are available, such as the General Atomics HTGR.

Indirect and supplementary costs are often calculated with standardized factors or formulas. For example, design costs can be calculated as a fixed percentage of construction costs, based on historical experience. These formulas are sometimes accompanied by cost-scaling equations; however, at this time no set of equations 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, which presents the process for top-down estimating. Despite its lack of cost detail, this method has the advantage in that it can be used to optimize designs such that the lowest LUEC can be realized.

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, computer-aided (CADD) tools, and data base systems, reactor system designs were nearly always fixed and completed before the detailed cost estimation process was initiated. Nuclear core physics, thermal hydraulics, safety limits, and other factors were usually integrated into the design 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 design process, allowing the possibility of LUEC and baseline capital cost optimization during design. For Generation I, II, and III reactor designs, this process was not readily available. The Generation IV design efforts have the opportunity for cost modeling to be directly integrated into the design process. One such costing process, used by Atomic Energy of Canada, Ltd. (AECL), is outlined in Appendix B.

The use of computer models to integrate 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). USDOE-NE used ORNL-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 are used to establish some of the scaling rules and to calculate 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 EMWG model 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 an early understanding of the costs of these programs, which could be in the hundreds of millions of U.S. dollars, before a demonstration unit is constructed. The demonstration costs could conceivably be in the 1- to 2-billion U.S. 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., U.S. dollar as of January 2001) per net kWe. Calculation of TCIC is discussed 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, and other factors that compose the normal year-to-year operations of the nuclear power plant. Some years may see capital upgrades or capital replacements that increase the annual cost. However, developers/estimators should average these increases 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 should be assumed constant over the economic life of the plant. Chapter 9 lists the O&M cost categories and the IAEA account system code number for each. Payments to the 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 longer than 1 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 life and reported in constant money per year. Chapter 8 lists the various activities, services, and materials that compose these costs.

2.4.5 Levelized Unit of Energy Cost and Its Components

The LUEC is the high-level figure of merit of most interest to utility decision makers. It is normally divided 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., U.S. dollar/MWh). Calculation of LUEC is covered in Chapter 9.

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3. ESTIMATING CATEGORIES FOR RESEARCH, DEVELOPMENT, AND DEMONSTRATION COSTS

One of the figures of merit for evaluation of Generation IV systems will be the projected costs of the 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, these costs are unlikely to be amortized into the LUEC, or levelized cost of other products, resulting from commercial operation of Generation IV systems (FOAK and NOAK reactors). Instead, most RD&D costs will likely be financed by governments, multi-governmental organizations, and/or public/private consortia. Such organizational entities are willing to support large RD&D expenditures because of the perceived environmental, socioeconomic, national energy security, nonproliferation, 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). This chapter discusses the rationale for selecting estimating categories and provides a comprehensive COA for RD&D activities.

3.1 Rationale for Selection of Estimating Categories

No existing COA structure, such as the EEDB or those used in the U.S. Department of Defense, fits nuclear reactor and fuel cycle RD&D costs. A generic RD&D COA, however, can be developed based on the WBS of past and present DOE/National Nuclear Security Administration programs (such as the former New Production Reactors Program and the present Fissile Materials Disposition Program). These programs can be divided into two major areas: reactor RD&D and fuel RD&D. Note 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. New fuel cycles often require the design and construction of demonstration or pilot plant facilities.

3.2 Comprehensive Code of Accounts for Research, Development, and Demonstration Activities

Table 3.1 lists the categories in a COA structure that should be found in a comprehensive, generic, successful Generation IV RD&D program. The expected technology development, planning, and prototype costs are itemized and expressed in constant dollars, including all costs necessary to bring a concept to the deployment/commercialization stage except 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 confidence should increase with development of the technology. Cost estimators should:

Identify the timing of each cost item (at the 50% confidence level).

Describe the cash flows for these items on an annual basis.

Report the prototype design and construction cost at the two-digit COA level.

Submit a complete text description of the methods and assumptions used in developing the costs with the tabular cost data.

Table 3.1 Generation IV International Forum Code of Accounts for research, design, and development 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 Instrumentation and Control 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/Probabilistic Risk Assessment

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 Rem. and Transport to Post-Irr. Exam. Site
RD348	Post-Irradiation Examination
RD349	Scient. Supervision of Post-Exam. Work/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 Oper. 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	Preparation of Fuel Qualification Plan
RD415	Preparation of Safety Analysis Report
RD416	Environmental Documentation for Permitting
RD417	Licensing Management
RD418	Quality Assurance Activities, Procedure Dev./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 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 FRAMEWORK AND ASSUMPTIONS

This chapter describes the general framework and assumptions to be followed in developing the base construction cost for the advanced reactor concepts, using methods appropriate to the level of design definition available. In the conceptual and preliminary design phases, the top-down estimating approach should be appropriate for the majority of the scope (Chapter 5); as design becomes more detailed, the bottom-up estimating approach will be more appropriate for most of the scope (Chapter 6).

Nearly all aspects of the framework are based on design and construction practices in the United States for past and existing nuclear projects. The same principles are expected to be appropriate for other regions though the level of cost detail may not always be readily available. Specific input from other regions and conversion of measurement units to international standards have been provided where possible.

Appendix G provides sample data to support the estimating process as well as examples of U.S. nuclear plant construction experience from the 1970s. Examples of top-down estimating techniques are provided in Chapter 5 and Appendix H. The following sections describe assumptions for project execution, the commercialization plan, estimate components, the project COA, project scope definition, qualifications, the project estimate, region and site definitions, the FOAK and NOAK plants, and the format for reporting cost estimates.

4.1 Project Execution

The assumptions on the organizational structure to be used in developing the cost estimate are described below, based on traditional U.S. business practices. Generation IV nuclear system projects may have a nontraditional structure. In either case, 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, 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 will provide overall project management. For module fabrication, a heavy machine fabricator or shipbuilder will 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 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, design plant buildings and structures, prepare all technical documentation and reports, provide all procurement services, and 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. 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 an addendum.

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.

4.2 Commercialization Plan

The following assumptions relate to the plan to commercialize the nuclear plant:

5. The first phase is project development through research and development. Each technology will be evaluated for compliance with the stated goals of this phase before approval to proceed to Phase II, conceptual design.
6. Successful designs from Phase II may proceed to Phase III, detailed design, including any prototype or demonstration testing and concluding with plant certification of a standard design.
7. Commercial plant commitments for multiple plants will be obtained before the first commercial plant (FOAK) construction on an approved site.
8. All awards for project services, procurement, and construction will be based on competitive bids for a series of identical plants.
9. Dedicated factory facilities for fabrication of plant equipment or factory modules will be constructed or adapted to support construction of the FOAK plant.
10. The commercialization plan should include establishment of plant design ratings and plant performance guarantees
11. The development of fuel fabrication facilities may proceed concurrent with the conceptual design and detailed design phases for the power plant depending on the source of first reactor fuel.
12. Fuel reprocessing facilities may proceed concurrent with the power plant conceptual design and detailed design phases, depending on schedule requirements for reprocessing services.
13. Subsequent plants up to the NOAK plant will be constructed without any significant changes in the certified design.
14. The NOAK plant is defined as the next plant after 8 GWe of plant capacity have been constructed. This rating, together with consideration of plant capacity, sequence, and timing of unit construction, provides a basis for calculating learning effect on cost of plants between the FOAK and NOAK plants.
15. For purposes of sizing the fuel fabrication and reprocessing facilities, a nominal fleet size will be 32 GWe for each reactor type.

Detailed design, certification, and other non-recurring costs should be separately identified and amortized over the plants before the NOAK plant.

4.3 Estimate Components

Cost estimators should describe estimate components and identify how they are handled in the estimating process and COA, including the following components:

- specifying unit
- common or recurring cost item
- nuclear island and BOP
- 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, capitalized and annual costs, financing, or decommissioning costs).

4.4 Project Code of Accounts

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.

1. The GIF COA (derived from the IAEA [2000] and EEDB [ORNL, 1988] COAs) will be the structure used for cost estimates. Sample EEDB COA for the advanced liquid metal reactor (ALMR), the modular high-temperature gas-cooled reactor (MHTGR), and a LWR are given in Appendices A, B, and C of Delene and Hudson (1993). See Appendix F for full GIF COA structure and dictionary.
2. Consistent COAs 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 detailed estimates summarized by COA can provide bulk commodity ratios to equipment cost that can subsequently provide the basis for current estimates with current pricing of process equipment costs.
3. Within the structure of the GIF COA, each technology will develop a detailed COA that uniquely defines the specific plant features to ensure full and exclusive scope for the project.
4. 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.

4.5 Project Scope Definition

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.

1. Whenever possible, the cost estimates should 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 should be defined in the SDDs. None of the Generation IV concept designs have thus far evolved to the point that these documents are available.
2. The project scope definition for each reactor concept is expected to consist of facilities and systems developed specifically for the reactor concept, some systems that are adapted from reference plant data, and others that are 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. The cost for all electrical power terminations, including connectors, should be attributed to 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.
4. 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 cost. These expenses include 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 in the control system cost.

5. Costs for routing, laying, or pulling wire and cable in ducts, conduits, and trays should be included in the electrical power system cost.
6. The costs for attachments to structures (e.g., anchor bolts and auxiliary steel) should be included in the equipment item requiring the support. Embedments (such as sleeves and attachment plates) should be included in the cost of structures.
7. The cost estimate for a system, equipment, facility, or structure should include those costs associated with fabricating, installing, and/or constructing the particular item described in the SDDs or building and structures design descriptions.
8. For costing purposes, the boundaries of a system, facility, or structure are as defined in the SDDs or building and structures design descriptions and in the piping and instrumentation diagrams (P&IDs).
9. 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 quality assurance/quality control overview. Any onsite fuel manufacturing, handling, reprocessing, or other fuel cycle facilities should be assumed to be nuclear-safety-grade.
10. Project scope definition for the indirect cost is typically defined separately from 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, direct hours should be quantified throughout the estimating process and be available by category of work or craft.
11. Non-manual services for field and home office are typically defined by staffing 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 detailed tasks with sequence logic in finalized estimates.
12. Engineering (Account 35) and home office services (Account 37) include the A/E costs for design, engineering, procurement, cost engineering, quality assurance/quality control, reproduction services, etc.
13. Any module fabricator (factory owner) costs for engineering, quality assurance, etc., should be separately shown. Reactor design costs by the manufacturer should also be separately shown.

4.6 Inclusions/Exclusions/Qualifications

The following assumptions provide qualifications for the estimate:

1. All engineering and cost information, including specifications, drawings, virtual construction and sequence (CADD output), all equipment, material, and labor resources, will be available as required.
2. The baseline construction requires no premium time (overtime) work to recover from schedule delays. Costs for possible overtime for schedule recovery should be reflected in the contingency cost (see Section 7.3.2). The use of premium time for normal baseline construction over and above a standard working week should be identified.
3. Funding will be 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 Appendix D for other site-related assumptions.

4.7 Project Estimate

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

1. The base construction cost estimates should 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 should include supplier profit margins.
2. Estimate details should be summarized to the two-digit level of the COA and provide input to other cost models for calculating the LUEC.
3. Installation costs should be based on quantities, installation rates (see Table G.1.3), and labor rates (see Table G.1.1). 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, 2007, pricing levels as depicted in Table G.1.2, productivity of the inherent direct labor as depicted in Tables G.1.3, and the cost of labor as depicted in Table G.1.1.
4. All construction should be estimated as direct hire, including specialty contractors. All field labor should be quantified and included as labor cost. Process equipment should be separated from all other equipment and material costs.

Estimate reporting format is discussed in Section 4.12

4.7.1 Estimate Pricing Date and Currency

Appendix G, Table G.1.3 provides bulk commodity unit hour installation rates for nuclear and non-nuclear construction practices. Table G.1.4 provides bulk commodity definitions. The craft labor rates shown in Table G.1.1 were obtained from the Engineering News Record Magazine publication for the fourth quarter 2006, dated 12/8/2006 for a medium labor cost on a U.S. site. The labor installation rates were developed by applying a productivity factor to estimated standard rates. Nuclear productivity factors were developed from a set of early nuclear projects, which did not experience post-Three Mile Island (March 1979) back-fitting. Non-nuclear installation rates were developed from current fossil power project experience. The commodity installation rates (Table G.1.3) are not a complete set needed to estimate costs of 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 G.1.2 were escalated from historical data by appropriate BLS index. Bulk commodity unit costs (Tables G.1.2) are intended to be a measure of bulk commodity pricing levels for the US region. Currency exchange rates for January 1, 2007 are shown in Table G.1.7

The following guidelines apply:

1. Cost estimates should be reported in constant dollars of January 1, 2007.
2. Any exception to the labor rates, commodity prices, and installation labor hours shown in Tables G.1.1 through G.1.3 should be justified.
3. The estimator should use cost information relevant to the reference date (January 1, 2007) where possible. If such information is not available, costs in terms of another reference year may be adjusted, where applicable, using appropriate cost indices. Table G.1.5 provides examples of such adjustment factors using Bureau Labor Statistics indices and other published data.

4.7.2 Direct Equipment and Material Pricing

The following guidelines apply to direct equipment and material pricing:

1. The cost of using any government-owned or -operated facility should be 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 separate construction concept whereby nuclear-safety-grade and Seismic Category 1 construction are separated from conventional industrial

construction. All costs of equipment, materials, storage, quality assurance/quality control, and labor productivity for the non-nuclear-safety areas should reflect conventional nuclear industrial practice. The portions or fractions of the plant constructed under each construction grade should be documented.

3. If a plant uses a new, dedicated factory for producing construction modules for the NSSS and/or BOP, the proper amortization of the factory cost over its production life should 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, including factory construction cash flow, capitalization, operations cost, and amortization assumptions (e.g., number of units assumed for factory capital cost recovery).
4. Most of the equipment for nuclear power plant systems should be estimated at worldwide pricing levels and not differ significantly by region. Equipment costs should be inclusive of vendor design, fabrication, testing and certification, packing for in-country shipment, and normal 12-month warranty. The costs are for items delivered to the site, excluding freight forwarding, ocean shipment, and customs clearances. The costs should include allowances for installation materials and any construction spares; any pre-service maintenance requirements should also be included. Plant startup, commissioning, and operational spares for 12 months should be included with indirect accounts.
5. Most of the non-process equipment and materials for nuclear power plant facilities or systems should be estimated at worldwide 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 G.1.2 should be provided with the estimate submission.

4.7.3 Direct Labor Productivity

The following assumptions relate to direct labor productivity:

1. All plant construction will be accomplished by the direct hire labor force except specialty tasks subcontracted by the A/E. Costs for all tasks, including subcontracted tasks, should 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 G.1.3 represent the productivity determined for U.S. advanced nuclear plant construction.
3. The rates represent a standard working week for a commercial plant and would be better than the rates for a test or demonstration facility. Additional improvements may be applicable for the NOAK plant (see Section 4.11 and Appendix E).

4.7.4 Labor Cost/Hour

The following assumptions relate to labor cost per hour:

1. Labor rates for craft labor employed to assemble equipment at any onsite fabrication shop will be the same as construction crew rates. Offsite craft wages at a module factory are likely to be lower and the work more productive, steady, and safer than for onsite fabrication but will incur factory overheads.
2. Composite cost per hour for manual labor includes a craft mix for the category of work; a craft crew consisting of journeyman, foreman, and apprentices; craft wages; premium cost (if any); travel or living allowances, geographic factors, merit factors, public holidays, and sick leave; vacation pay; pension funds; medical insurance; unemployment insurance; and all labor-related costs paid by employers 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 should be included with the indirect accounts.

5. Composite labor costs (base rate plus fringe benefits) to be used for the U.S. site in 2007 dollars are given in Table G.1.1.
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. These costs exclude office supplies, office equipment, office space, travel, relocation, training, and other ancillary costs.

4.7.5 Field Indirect Costs

Indirect cost accounts consist of all costs that are not directly associated with a specific permanent plant. Examples include Accounts 31 (Field Indirect Costs), 32 (Construction Supervision), 35 and 37 (design services), and 36 and 38 (PM/CM services). For these costs, the following assumptions apply:

1. Material handling for major equipment, maintenance of permanent plant equipment before plant startup, and crane operators and truck drivers for support of direct account activities should be included with direct accounts.
2. Only multi-purpose, multi-craft scaffolding and staging should be included in indirect Account 31. Single-craft scaffold and mobile platforms should be included in direct accounts.
3. Individual craft cleanup should be included in direct accounts, while general site cleanup and trash handling should be included in indirect Account 31.
4. Installation spares should be included in direct accounts, while spare part requirements during start up testing should be included in indirect Account 33 or 34. Operating spares should be included in supplementary cost Account 52.
5. Construction testing of installed systems should be included in direct accounts. System pre-operational testing and startup activities should be included in indirect Account 33. The plant demonstration test run should be included in Account 34, while operator recruitment, training, and other associated costs should be included in owner Account 40.

4.8 Project Schedule

The results of the project estimating effort provide the necessary basis for the development of a project schedule. The estimate provides quantification of the physical plant as well as labor hours that are to be expended for each major account. Previous major projects or Nuclear power project experience should be used to establish the relationships between commodity quantities, staffing levels and durations for each of the second level account codes. The following guidelines are provided for developing the overall project schedule and major milestones.

4.8.1 Assumptions

Preceding the development of the overall project schedule, certain assumptions provide the basis and framework for the effort. The following assumptions are a pre-requisite for the schedule:

- All non-recurring design completed for the specific site,
- All procurement packages and specifications available,
- Any required proto-type plants have been constructed and operated,
- Standard plant design has been licensed,
- Licensed site is available,
- Proven fabrication facilities exist,
- Experienced Architect/Engineer organization is used,
- Construction performed with direct hire labor,
- Qualified construction craft personnel available at site without additional cost for recruitment, training, relocation, travel or housing,
- No cash flow constraints exist,

- No regulatory or political constraints remain,
- Availability of all equipment and materials on an as-needed basis, minimizing the on-site material handling and warehousing requirements but ensuring options for continuity and work-around planning,
- Work to be performed on a regular 5 day work-week of 8 hours per day on a single shift. For the NOAK plant, alternative schedules may be developed for accelerated construction using different work weeks such as rolling 4 x 10's or multiple shift work.

4.8.2 Design

Site specific designs (non-recurring) are finalized for adopting the standard plant to the requirements of a specific site; see Appendix C - Site Related Engineering and Management Tasks.

4.8.3 Procurement

Multiple plant orders are in-hand prior to start of the FOAK plant. Commitments for multiple plants have been made with progressive release of deliveries to meet individual plant requirements.

4.8.4 Construction

The completion of the standard plant design will include development of detail construction plans and schedules based on resource loaded work packages sequenced to minimize the construction schedule and financing costs. The designs incorporate constructability reviews for efficient fabrication and construction processes.

The FOAK plant construction schedule should be based on actual construction experience of typical Nuclear power projects of similar or relevant type and rating.

4.8.5 Site prep to start of structural concrete

The typical duration for the standard plant should be modified for the requirements of a specific FOAK plant site.

4.8.6 Fist structural concrete to plant start-up

Initial construction schedules may be developed for combined categories of commodity construction, identifying progress and phasing of major categories such as Concrete, Piping, Mechanical, Electrical and Instrumentation.

More detailed schedules may show similar activities for each major facility of the plant.

All the commodity installation activity durations should be compatible with actual nuclear plant construction experience for sustained installation rates of quantity per month during 10%-90% progress.

The overall construction durations and sequence should consider the plant configuration, access requirements, availability of work space and floor areas within each facility as well as overall site labor staffing levels.

Craft staffing requirement curves should strive for continuity of individual craft requirements while minimizing peaks.

The sequence of construction activities is to be integrated with the requirements for construction testing and plant startup activities for facilities, services and process systems.

4.8.7 *Plant startup to fuel load*

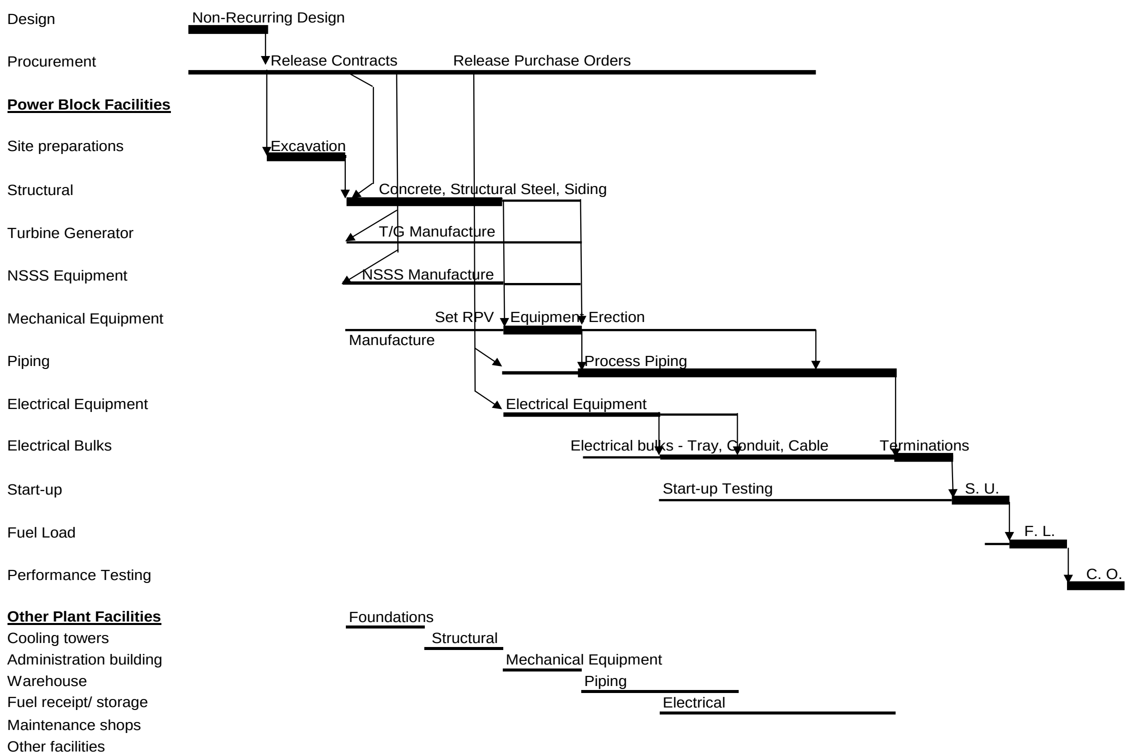
Construction activities should identify the early start points for plant start-up activities commencing with component testing, system testing and facility start-up activities prior to fuel-load.

The schedule should show any restraints for availability of first core fuel relative to completion of any fuel fabrication facilities.

4.8.8 *Fuel load to commercial operation*

Fuel Load and gradual power ascension duration should consider the specific reactor requirements and logical sequences leading to full power commercial operation. Milestone events for criticality, turbine roll, various stages of power ascension to full power rating and any performance acceptance testing should be shown.

Figure 4.1 Sample FOAK project schedule



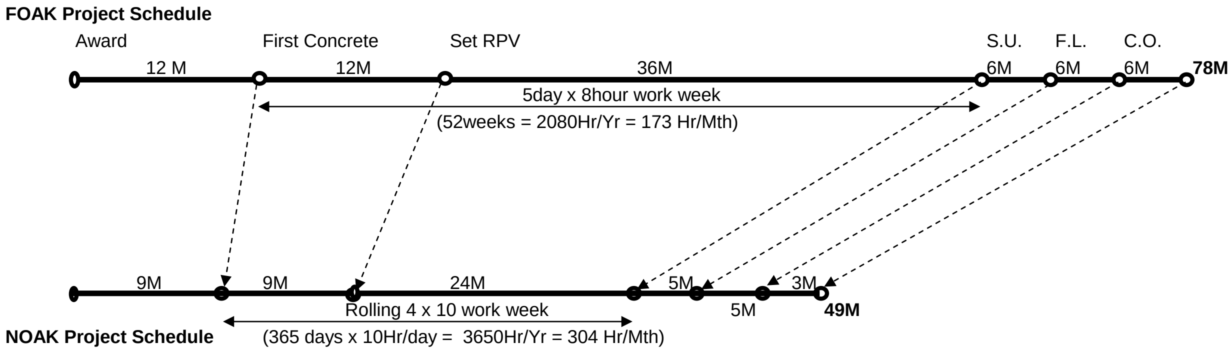
4.8.9 *NOAK plant project schedule*

The schedule and cost estimate for the NOAK plant may include accelerated construction work week plans such as a rolling 4 x 10s or multiple shifts. Construction support services should be specifically developed to support the accelerated schedule requirements.

For comparisons of the benefits to be derived over time, a summary of the FOAK plant schedule should be shown together with an equivalent NOAK plant schedule summary. All major activities should be linked for a direct comparison of the durations for design, site preparations, construction, startup testing, fuel load and acceptance testing.

The basis should describe all assumptions and provide appropriate supporting data.

Figure 4.2 Comparison of FOAK to NOAK project schedule



4.9 Region and Site Definition

The guidelines currently consider the Americas, Asia, and Europe in developing plant estimates, with the following assumptions and guidelines:

1. Site/seismic conditions for each region are considered in Appendix D. Most current North American, Asian, or European reference site data are proprietary and cannot be used in guidelines.
2. Site land (Account 11) should be based on the estimated site area, including any buffer zones (200-hectare minimum) and a cost of $37,000/hectare in the U.S. The total land cost is assumed to be 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 Figure 1.1 under deployment: (1) the standard plant cost (i.e., the types of costs that will be repeated in subsequent costs such as site-related design and construction); and (2) the true FOAK non-recurring costs, such as design and design certification costs. Exceptions should be clearly identified. Regarding fuel cycle FOAK costs, the fuel cost for all units, FOAK through NOAK, should include their fair share of the life cycle costs for a new fuel cycle facility constructed either onsite or offsite. Fuel facility construction costs should be part of these fuel-related life cycle costs.
2. Each system development team (proponent) should perform the estimates for the standard FOAK plant based on current construction experience for similar facilities. Learning experience can be included for the 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 should include the cost for all site-specific licensing or pre-licensed sites. A generic plant design approval (certification) should be part of the FOAK non-recurring deployment costs.
4. Standard plant costs include all engineering, equipment, construction, testing, tooling, project management, and any other costs that are repetitive (recurring) in nature and would be incurred in building an identical plant. Appendix C presents a sample listing of mostly site-related repetitive engineering and management tasks.
5. Appendix E deals with learning and the relationship between the capital costs of the FOAK and NOAK plants. Because system development teams are estimating FOAK costs, Appendix E discusses how NOAK costs can be reasonably estimated from FOAK costs.

4.11 NOAK Plant

The following assumptions apply to costing the NOAK plant:

1. Design will be identical or nearly identical to the first commercial plant (any engineering or license changes from the FOAK plant must be amortized).
2. The plant site will be enveloped by the reference site conditions.
3. No product improvements will be incorporated; that is, the first commercial plant design is frozen.
4. Equipment manufacture and plant construction will be performed by the same contractors as for the first set of plants.
5. All awards for project services, procurement, and construction will be based on competitive bids for a series of identical plants.
6. There will be no changes in USNRC (or other national) regulations or major codes and standards subsequent to the first plant.
7. The cost estimate should include the cost for all site-specific licensing or pre-licensed sites. A generic plant design approval (e.g., design certification in the U.S.) should be assumed.
8. 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).
9. Nonrecurring engineering and home office services costs of the reactor manufacturer or major process equipment manufacturer will be zero for the NOAK plant. Any applicable recurring engineering costs should be identified.

4.12 Estimate Reporting Format

The format to report cost estimates should have the following characteristics:

1. Capital costs should be separated into two categories related to whether the equipment/construction is nuclear-safety-grade or industrial-grade. The plant design contractor will determine the boundaries of the nuclear-safety-grade and industrial-grade areas. Costs within each category should be reported in the GIF COA format. (see Appendix F).
2. Although included and reported in the overall plant estimate, costs of common plant facilities should, in addition, be identified at the two-digit account level and listed separately in the GIF COA format.
3. In cases where equipment items or piping are combined with structures to produce a factory-assembled equipment module, a worksheet documenting each module should be prepared. The worksheet should identify by three-digit GIF COA the applicable items and costs that compose the module. For each three-digit account, the worksheet should 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 should 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 should 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 to 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 should 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 costs should be fully supported in the future cost estimate reports. For large equipment items and modules, the site-delivered transportation costs should be identified as a line item.

4. For large factory equipment items, such as the reactor vessel and internals, steam generators, and heat exchangers, supporting cost data by component must be available for review. The supporting data include factory material cost, material weights, factory labor hours, recurring cost, and total cost for each equipment item.
5. All construction should be estimated as direct hire, including specialty contractors. All field labor should be quantified and included as labor cost. Process equipment should be separated from all other equipment and material costs.

Table 4.1 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

References

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Reed Business, 1992, *Means Building Construction Cost Data*, Reed Business Information Co, New York, NY, U.S.

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5. GUIDANCE FOR TOP-DOWN COST ESTIMATING

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 complete bottom-up cost estimate. Therefore, a more global approach is needed to help the designers and decision makers compare 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 two-digit level as well as some of the three-digit GIF COAs, with aggregation of the corresponding 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; if suitable cost data are available, they could be used to estimate costs for the 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 used; other techniques could be used if the resulting estimates are validated to current pricing data. These guidelines do not provide a comprehensive handbook on cost estimating of future nuclear systems; such a handbook would need to include more exhaustive data, detailed method descriptions, and extensive examples of complete energy plant estimates, which are 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 to meet 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 rough conceptualization, the designer should 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 estimates have also been proposed for U.S. 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 approximately estimate costs 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 COA to the appropriate level of detail. Components of an estimate may be developed at a high level of detail and summarized to a consistent COA level for inclusion in the overall estimate.

An estimating technique developed for the petrochemical industries uses cost of process equipment, which is typically defined early in the project definition, and then applies bulk factors for other commodities that typically are not detailed when the initial estimate is undertaken. Applying this technique to advanced reactor concepts would require that bulk factors be derived from similar nuclear power or non-nuclear project cost data. Costs of bulk commodities such as concrete, pipe, electrical supplies, and instrumentation should be expressed as a fraction of process equipment cost. Similarly the direct craft job hours required to install the process equipment and bulk commodities should be expressed as a ratio to process equipment cost.

5.2.1 Top-Down Modeling by the Designers

Generally, the designer of a new concept already has a coherent conceptual image of the system and its possible variations but very little insight on its construction cost. To evaluate this cost, the designer may take two main steps: (1) decompose the concept into several cost modules and (2) identify the most suitable methods to estimate the cost of each element of the 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 or system or major process equipment such as a pressure vessel). At a minimum, the cost modules should correspond to the two-digit level of the COA structure. The cost of each element should be estimated usually by comparison with other elements for which costs are better known. The methods available for cost estimation may be classified into two categories, direct analogy and modeling, as shown in Table 5. 1

Table 5.1 Two methods for top-down cost estimating

Characteristic	Direct Analogy	Modeling
Principle	Integrate the element in a homogeneous family	Determine differences between the element and a reference, and construct a model mimicking the variations of the element
Advantages	Fast, low cost, transparent, credible for an homogeneous family	Fast, flexible, dialogue tool
Disadvantages	Data intensive, lack of detailed precision	Not transparent, requires training

Direct analogy necessitates a sufficient number of cost data. It is applicable, for example, to gas turbines whose prices are published worldwide as well as for other systems consisting of equipment, pipes, pumps, HVAC devices, and similar items. Modeling is used generally when direct analogy is not possible.

A large number of modeling approaches have been developed and described to estimate construction costs (see for example Chauvel *et al.*, 2001, and Peters *et al.*, 2003). To estimate construction costs of Generation IV nuclear energy systems, the exponential methods are the most relevant but factorial methods are also interesting, notably for the ratios of equipment cost to functional unit installed (see Chapter 3.2.1 of Chauvel *et al.*, 2001).

The cost of process equipment or complete process systems may be related to similar reference plant data with adjustments for size, capacity, or rating, using exponent cost factors similar to

$$C = A + (B \times P^{n})$$

where

C	=	the cost of the subject plant element
A	=	a fixed component of the reference plant cost
B	=	variable component of the reference plant cost
P	=	ratio of subject plant to reference plant component parameter value
^{n}	=	exponent that reflects the size benefit of rating for the component. See table 5.2
P^{n}	=	equivalent to a cost factor for ratio of parameters between subject plant and reference plant data.

Table 5.2 Sample size/rating cost exponent factors

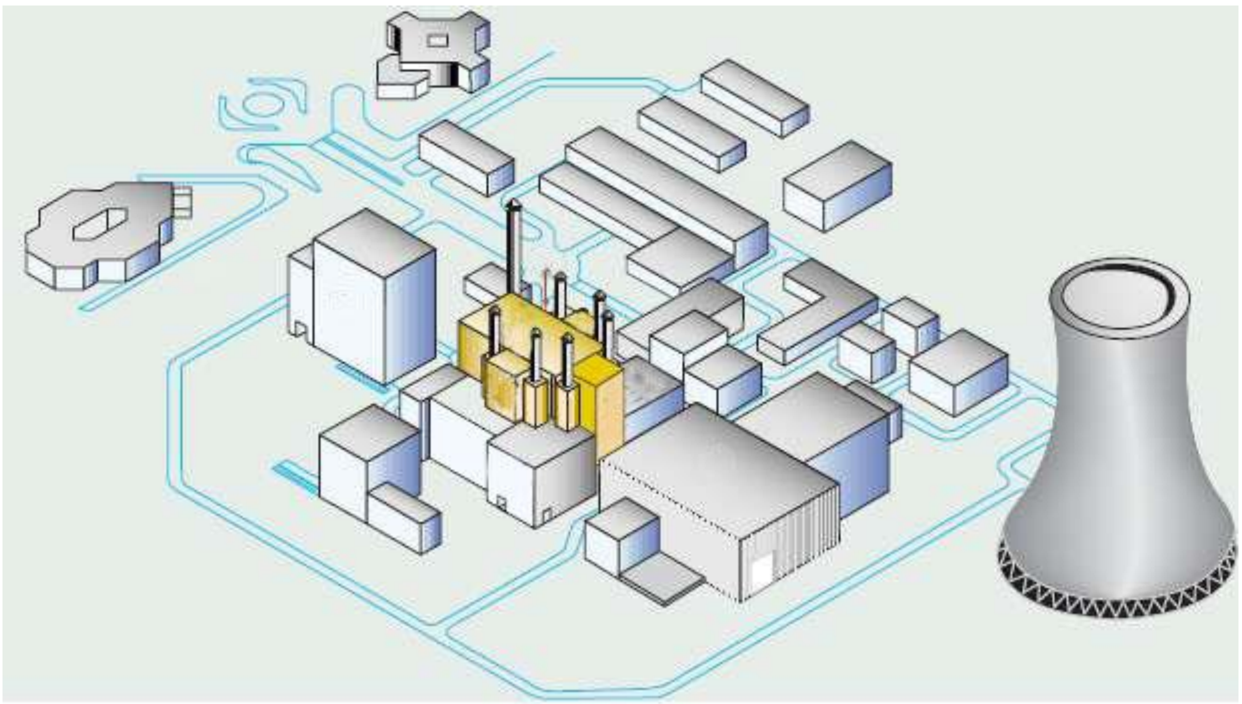
Plant	Rating (unit of measure)	Cost Exponent
Generation Plant		
Steam Turbine	kWe	0.50
Diesel Generators to 500Ton/min	kWe	0.62
Diesel Generators to 120Ton/min	kWe	0.72
Gas turbines	kWe	0.50
Combined cycle gas turbine	kWe	0.48
Chemical Plants		
Acetone production plant	TON	0.45
Ethylene production plant	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

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 equipment such as pipes and pressurized vessels (pages 627 to 634 of Peters *et al.*, 2003).

5.2.2 Application to Nuclear Reactors

A nuclear reactor plant is usually represented as shown in Figure 5.1.

Figure 5.1 Arrangement of a nuclear reactor plant



Inside each of these buildings are civil works, equipment, electrical and mechanical systems, and other systems. These elements are gathered at the two-digit level of COA cost modules.

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

As an example, a cost evaluation model for high-pressure, stainless-steel-lined vessels, like the ones used in PWRs, was developed from available data in the nuclear industry. The following equation was found to give a good estimate of the supply cost of such vessels.

$$\textit{Reactor Vessel Cost} = A[(B \cdot dv + C) \cdot (hv/3)^{0.5} \cdot (dv/0.6)^{0.1} \cdot (D.pv + E)]$$

where

dv = *vessel diameter*

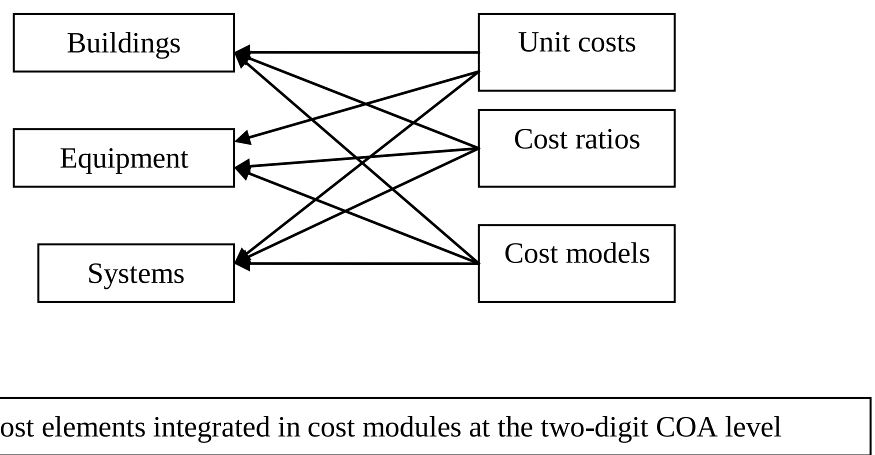
hv = vessel height
pv = design pressure of the vessel
A, B, C, D, & E are the adjustment coefficients.

The adjustment coefficients are obtained by applying well known statistical techniques (e.g., ordinary least squares). 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, the model is validated by comparing the model output to current vendor pricing data, historical data, or detailed reference plant estimates.

5.2.3 Top-Down Estimating Process

The top-down estimating process is illustrated in Figure 5.2.

Figure 5.2 Top-down estimating process



For buildings, formulae exist to estimate the construction cost starting from the baseline cost of m^3 of concrete or baseline cost of m^3 of building volume. For equipment, ratios and specific models are used. For systems, unit costs, cost ratios, and models are used, depending on the level of design detail.

Appendix H provides examples of top-down cost estimating processes.

5.3 Use of Top-Down Modeling for Generation IV Systems

Top-down cost estimating requires the use of a reference conceptual design and reference plant data, which can be used in design option studies and generic studies.

5.3.1 Reference Conceptual Design

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

1. A description of the process and its reference operating conditions (including energy and material balances).

2. Schematic figures of the major components (reactor vessel, steam generator, heat exchangers, etc.) and of the main systems with size and layout arrangements.
3. The types, main measurements and volumes of the buildings of the nuclear island, including containment.
4. A description with major dimensions of the facilities outside the nuclear island.

5.3.2 Reference Plant Data

A reference conceptual design cost model is an assembly of several models and data allowing cost estimates that represent the concept studied. The reference plant data may consist of several plants with systems or components that are similar to the subject plant. The reference plant cost data should be the basis to estimate costs for the subject plant design. Reference plant data will consist of technical and physical scope information defined by P&IDs, SDDs and data sets, process flow diagrams, and facility arrangement drawings. The corresponding cost estimate with details to commodity level will typically include COA, description, quantity, equipment cost, material cost, hours, labor cost, and total cost by line entry.

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 to establish the cost factor from the ratio of parameter data, as discussed in Section 5.2.1.

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 applying 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.

The estimate definition should 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.

Reference plant data are used in the following ways:

1. Before any part of the reference plant cost data is used, 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 should 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 should 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, should 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 plant's COA serves as a basis to ensure that the scope of the reference plant is adequate to apply the top-down or some other estimating technique such as equipment bulk factors or a bottom-up commodity detail estimate. Different reference plants can be utilized that are most appropriate for the scope of the subject plant. Each segment of the entire project scope can be associated with the estimating technique that is the most appropriate to it and with reference plant data.
8. A completely normalized and relevant cost data base in line with the GIF COA structure is highly recommended to facilitate transparent, traceable cost estimates by the plant design team.
9. The team should select 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. The team should then establish an appropriate major parameter for the selected scope and calculate a cost factor for the ratio of the parameters between the subject plant and reference plant ratings.
11. An estimating cost model consists of links to the reference plant detail estimate; all the cost factors required normalizing the data for the subject plant, system, or COA for the selected COA; and resultant COA detail for the subject plant. The model should include the ability to check and validate the resulting subject plant direct cost estimate and refine COA adjustment factors for the details.
12. Information related to quantities of materials and labor requirements extracted from data available on the reference plant provides input to support the development of a construction schedule. The construction schedule and costs can be refined through an iterative process, taking advantage of progress in the development of the detailed design.
13. Validated cost details should be summarized to the two-digit level of the COA and provide input to other cost models to calculate LUEC.

5.3.3 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 optimization should be completed before launching into more detailed studies using a fixed baseline design. In the course of further engineering studies, both bottom-up and top-down approaches can be used to better estimate the costs of the different parts of the Generation IV systems, including innovative fuel cycles.

5.3.4 Generic Studies

Generic studies to analyze size 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).

5.4 Top-Down Approach for Indirect Capital and Non-Capital Life Cycle Costs

Most of the discussion in previous sections dealt with the top-down scaling of equipment and structures for the new concept. These costs would be summed to the two-digit level as Accounts 21 to 28. Indirect costs are mostly project support labor costs, which are not usually estimated early in the RD&D program. There are, however, guidelines that can be used to calculate the indirect costs (Accounts 30) as a fraction of the direct costs. A literature review can find the best algorithms. Engineering-economic textbooks often contain such cost-estimating relationships for conventional industrial and chemical facilities.

For example, a technique was previously developed for Generation III+ plant field indirect costs. Field indirect costs comprise three categories of indirect 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
3. Time-related costs such as construction equipment rental, site cleanup, and temporary facility maintenance.

Actual cost data were analyzed and costs defined for the three components for a typical 1,200-MWe project, nuclear island (NI), and BOP scope. An algorithm was developed to calculate the COA 31 - field indirect costs for any size plant and construction schedule. The algorithm updated for 1/1/2007 costs are as follows:

$$NI = \underbrace{6.85 \times 10^6 (P/1200)^{.33}}_{\text{Fixed}} + \underbrace{0.48\, LN}_{\text{Scope}} + \underbrace{4.30 \times 10^5 (P/1200)^{.5} M}_{\text{Time}}$$

$$BOP = 6.85 \times 10^6 (P/1200)^{.66} + 0.34\, LF + 4.30 \times 10^5 (P/1200)\, M$$

where

NI = Nuclear Island field indirect cost
BOP = Balance of Plant field indirect cost
P = Plant rating (MWe)
LN = Labor cost for the Nuclear island
M = construction duration (Months)
LF = Labor cost for the BOP scope.

Similar algorithms can be developed for other indirect costs such as construction supervision, design services, and PM/CM services.

5.5 Other Life Cycle Cost Elements

The following life cycle elements also need top-down estimating techniques:

- **Pre-Construction Costs:** See appendix F - COA definitions for all pre-construction cost items. Land cost pricing is discussed with section 4.8 - Region and Site Definition
- **Contingencies:** If an integrated design/cost model exists, an uncertainty analysis can be used for contingency calculations as explained in Appendix A.
- **Interest During Construction:** This is handled in the same way as for bottom-up estimating (see Chapter 7) 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 Startup Costs:** A cost-estimating relationship can be developed from historical data that present startup 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) 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 (Nisan *et al*., 2003).

- **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 to develop capital and operating costs for a new type of fuel fabrication or reprocessing facility. The guiding principles would be the same as for developing cost-estimating relationships for the reactor plant, as described above. Chemical and metallurgical industry cost-estimating relationships should be useful.
- **D&D Costs:** For 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.

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6. GUIDANCE FOR DETAILED BOTTOM-UP COST ESTIMATING

This chapter defines the bottom-up estimating guidance. 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 specific assumptions underlying cost estimate preparation. Section 6.3 gives guidance for construction costs. Section 6.4 outlines guidance for other project costs. Sections 6.5 provides some additional guidance for detailed plant cost estimates and Section 6.6 provides detail estimating notes by discipline. Section 6.7 briefly outlines the requirements for other plants.

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 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 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

Cost categories are depicted in Figure 1.1 and may consist of the following:

- System R&D costs – All costs incurred in the research and development of the reactor concept before detailed design. These costs are discussed in Chapter 3. Most R&D costs will likely be financed by governments, multi-governmental organizations, or public/private consortia. This cost category is excluded from estimated costs of FOAK or NOAK plants.
- Prototype plant cost – Cost of constructing any plant element or complete plant necessary to prove, demonstrate, or test FOAK components of a plant. This cost category is considered similar to R&D costs and is excluded from estimated costs of FOAK or NOAK plants.
- Non-recurring costs – Cost of generic design and licensing for a standard plant, excluding all site-specific deviations from the standard plant and site-specific licensing and permitting. These costs are amortized over all the plants starting with the FOAK plant and before the NOAK plant. The NOAK plant cost excludes all non-recurring costs. These costs should be accounted for separately in the final evaluation of each reactor concept.
- FOAK plant cost – Cost of the FOAK plant including all site-specific licensing, permitting, and initial construction costs of a standard plant. This cost category reflects estimates based on known pricing and productivity typical for a nuclear facility at the regional site. It includes the FOAK portion of the non-recurring costs that are amortized over all plants before the NOAK plant.
- NOAK plant cost – Cost of the NOAK plant after gaining experience and learning from construction and operation of all plants before it. The category excludes all costs that were amortized over all preceding plants before the NOAK plant.

Costs should be expressed in constant reference year dollars. The data tables for specific estimating parameters in Appendix G 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) should 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. 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) allow 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, allowing 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 detailed estimate is usually calculated when the design reaches sufficient detail to quantify major project scope to the commodity level, including a comprehensive equipment listing supported by data sheets and P&IDs for all the process systems as well as most non-process service systems. The facility structural details should also be sufficiently developed to quantify rebar densities for slabs, walls, and other structural components. Electrical detail may be just at single line levels, and the controls may be limited to control room and overall plant control concepts.

As the project evolves, detailed estimates may be calculated for the initial budget, the preliminary project estimate, and a final project estimate, which may be the basis for contractual budgets for the life of the project.

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

6.2 Specific Cost-Estimating Guidance

The following guidance may be used to develop the base construction cost estimates using bottom-up detail estimating techniques:

1. The project scope definition is at a fairly definitive level 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, and control room equipment.
2. Some of the commodities such as electrical cable or field instrumentation may not be sufficiently detailed when initiating a bottom-up detailed 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 should be quantified to commodity levels to the same detail as the composite unit pricing and unit hour applications. For example, the scope of structures and concrete category of work include quantification of commodities for Account 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. 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 G.1.4 through G.1.6). The installation costs should be based on quantities, installation rates (see Tables G.1.7 through G.1.9), and labor rates (see Tables G.1.1 through G.1.3) 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), Material Cost = (number of units required in plant) x (cost per unit), and Equipment 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 should be included at the detailed record level to support summarization and reporting requirements described in Section 4.11. Reporting includes separation of the plant cost estimate into nuclear and non-nuclear costs, unitized and common costs, recurring and non-recurring costs, etc. See discussion in Chapter 4.
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 of bulk commodities can support procurement, delivery, and installation progress reporting. Bulk commodity quantities may be committed for total project needs and released to meet schedule requirements. Eventual testing and startup activities are supported by the GIF COA coding that was initially defined during the bottom-up detailed estimating process.
8. Each three-digit or lower GIF COA detail should 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 should be developed with a standard composite cost per hour by category of work. Each detailed record should then be extended for a total cost.
9. Each detailed record should carry coding to identify the scope or quantity basis and the basis for pricing equipment or material costs. The quantity basis should identify how the quantity was developed, and the pricing basis should come from the standard commodity unit rates, except when a record is created with specific input unique to the project. This information compiles total project costs on a pricing basis and provides input to contingency cost assessments.
10. All construction should be estimated as direct hire, including specialty contractors. All field labor should be quantified and included as labor cost. Process equipment should be separated from all other equipment and material costs.

Estimate reporting requirements are discussed in Section 4.11.

6.3 Construction Costs

The estimate kick-off package summarizes project status and the framework for the estimate and discusses the methodology for the quantification, pricing, and labor development for all the components of the project scope. To ensure an efficient start, scoping documentation packages should also be assembled for each discipline estimator. All senior team members, including project management, engineering, procurement, and construction, attend an estimate kick-off meeting to familiarize everyone with the forthcoming effort and ensure appropriate support with minimal disruption.

The estimate kick-off package includes the following:

1. Background – provides a brief history of the project, placing the estimate deliverable in 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. Participants and division of responsibility – identifies the team members and their areas of responsibility for the estimating effort.
5. Documentation of estimate basis – identifies the process for transmittals and documentation for all bases reflected in the estimate.
6. Coding requirements – describes the project COA and other type of information to be gathered and coded during the estimating process for all project needs.
7. Service estimates – describes the requirements to estimate services by each participating organization including identification of tasks, staffing levels, durations, staff salary grades, staffing levels, and other cost input.
8. Quantification of capital plant – describes in detail the available scoping basis and the methodology to be used to quantify each commodity for each discipline. This is the major section of the estimating effort supported by project control personnel. The methodology identifies take-off items and those that will use some parametric approach for concurrence by the team. The section also identifies where reference project data are used. The basis for each commodity quantity should be identified by a code.
9. Labor development for direct costs – describes requirements to utilize standard unit hours for subsequent application of site productivity factors. Composite labor cost per hour should have been previously developed with input from construction and labor relations departments. The rates should be calculated by category of work and estimating discipline.
10. Material and equipment pricing for directs – provides guidelines to develop commodity unit prices for the estimating programs and scope quantity records. The section identifies where reference project data are used. The basis for each commodity quantity should be identified by a code. Procurement department support requirements should be identified. The section also provides instructions for inclusion or exclusion of items such as tax, freight, escalation, warranty, spare parts, or vendor support.
11. Direct cost validation checks – identifies requirements to compare and reconcile previous estimates and actual project data with tabulation of ratios and other parameter checks to validate the current estimate at direct cost levels.
12. Field indirect cost – identifies responsibilities for input and review for the indirect cost components such as support craft labor, temporary facilities and services, construction equipment, tools and supplies, non-manual staff, office costs, insurances, bonds, and startup support requirements. The section also identifies requirements to compare and reconcile any previous estimates and/or reference project current or historic data and defines the requirements to tabulate ratios and other parametric validation of the indirect accounts.
13. Construction schedule – lays out the schedule developed after the scope and quantities have been reviewed and finalized, basing sequence and activities on category quantities and basing durations on historical sustained rates of installation. The section further defines the schedule to reflect the proposed project execution plan, construction work week, and 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 – provides level of effort staffing plans for PM/CM services, including design costs for remaining tasks based on quantity of commodity to be designed and budget rates of production. This section also defines other tasks for level of effort and the project schedule. Estimated salary grades are assigned to 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 – summarizes the estimate by the coded basis of scope and pricing, with the project team providing 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 team should conduct the assessment in accordance with the estimating guidelines for the project.
16. Reviews – identifies the series of reviews and supporting data to be presented. The team should conduct all initial reviews with engineering for all the project quantities before proceeding with other cost development. The team should also conduct discipline reviews with participation from engineering, procurement, and construction. Project schedules should be reviewed with the project construction and construction management departments. The total project cost estimate should be presented for management review, with support from the engineering, procurement, and construction team. The project management team should present the information to corporate or governing agency directors for final review and approval of the project budget.

6.4 Other Project Costs

Accounts 30 through 60 compose other capitalized costs. These costs should be estimated after the construction cost and schedule have been resolved. The costs describe 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.

TCIC summarizes Accounts 10 through 60 and serves as the basis to calculate total capital at risk (see Chapter 7). The cost estimating team should develop cash flow projections for single-digit COA, using the project schedule and expenditure curves and use cash flow summaries to calculate IDC.

When capital cost has been calculated, the team should use it as input to develop the annual operating costs with staffing levels by department, position and salary grade, consumables, lubricants, and other supplies quantified for annual costs.

The team should summarize details at the two-digit COA and provide them as input to separate cost models for calculation of LUEC for capital cost, fuel, and annual O&M cost components.

6.5 Power Plant Detailed Bottom-Up Estimating

The following guidelines apply to specific power plant estimates. Estimating teams should:

1. Initially estimate project indirect costs with algorithms similar to the top-down estimating technique described in Section 5.4. Subsequent project definition may include individual account quantification, unit pricing, and staffing requirements developed by task and duration. Composite costs per hour of labor may eventually reflect actual salary levels by grade of personnel.
2. Use cost summaries based on standard unit rates and standard labor cost per hour to directly compare among alternative reactor concepts. The differences in direct cost will essentially be scope related for each reactor design.

3. Develop appropriate cost factors to adjust the standard unit rates to each region 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.
4. Use direct cost summaries based on the region-adjusted unit rates as the basis to tabulate FOAK and NOAK plant costs. Appropriate learning adjustment factors, amortization of non-recurring costs, and other considerations will produce two-digit COA summaries that in turn will provide input to other cost models to calculate LUEC.

The relationship of project costs for the different reactor concepts may change for different regions. Labor productivity and composite cost per hour will likely contribute to an increase or decrease in the LUEC for the regions considered. The resultant LUEC costs serve as the final cost comparison among different reactor concepts. Other considerations such as proliferation or sustainability may contribute to the comprehensive evaluation of the recommended reactor system.

6.6 Discipline Notes for Scope/Quantity Development

The estimate kick-off package discusses major techniques to develop scope and quantities by discipline. The project team should consider the costs of providing any additional details compared to increased 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.

Table 6.1 presents previously used methods of quantity development for bulk commodities during the initial detailed bottom-up estimating effort. The team should agree on the methodology during the kick-off meeting with engineering support for the necessary tabulations, drawings, or sketches. Quantity development remains under the responsibility of the estimating team, but with computer modeling and automation, some of the quantity data may be better defined under engineering team responsibility.

Table 6.1 Quantity development methodology

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

Category/Commodity	Methodology
Mechanical	
Process equipment	Per equipment list verified with P&IDs
Non-process equipment	Per equipment list, P&IDs 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 marked up on arrangement drawings
Process systems valves	Take-off from P&IDs 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
Power control and instrumentation 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 marked up on site plan plus route length of cable tray
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&IDs
Control valves	Take-off from P&IDs
Instrumentation bulks	Reference plant date ratio to field-mounted instruments

Project scope guidelines and parametric data that typically are not available at the time of initial detailed bottom-up estimate include the following:

Reinforcing steel weight ratio to volume of concrete by structural component
Embedded metals weight ratio to volume of concrete by structural component.
Service building allowance quantity of composite concrete per floor area.
Service building allowance for architectural items and services per floor area.
Miscellaneous steel quantity as percentage of structural steel.
Architectural finish cost and hours per floor area by building.
HVAC system ductwork and controls cost and hours per building volume by building.
Small pipe quantity as percentage of large pipe.
Pipe hangers percentage of cost and hours of large pipe.
Pipe insulation percentage of cost and hours of large pipe.
Piping miscellaneous operations percentage of cost and hours of large and small pipe.
Instrumentation bulk quantity ratio to field instruments.
Instrumentation control panels cost and hours per length of field panels.
Power, control, and instrumentation (PCI) cable development guidelines.
PCI cable connection quantity development guidelines.
PCI exposed conduit development guidelines.
Non-metallic underground conduit quantity development guidelines.
Lighting fixtures quantity per floor area by building.
Lighting wire and conduit quantity, cost, and hours per light fixture.
Lighting panels and miscellaneous equipment cost and hours as percentage of light fixtures.
Communication systems cost and hours per floor area by building.
Security system allowance cost and hours
Grounding system conceptual quantity, cost, and hours development guidelines.

6.7 Other Plants

Similar estimating processes are applicable to estimate hydrogen production, desalination, or other co-generation concepts. Estimating teams should merge summaries of the direct costs with the power plant direct cost before estimating the indirect and owner accounts for the combined project. Two-digit COA summaries will provide input to other cost models to calculate LUEC and levelized unit product cost (LUPC). The guidelines for dedicated fabrication facilities, fuel fabrication plants, and fuel reprocessing plants are detailed below.

6.7.1 Dedicated Plant Fabrication Facilities

When estimating costs for dedicated fabrication facilities, teams should:

Estimate any dedicated factory proposed for fabrication of major equipment or structural modules in detail for the construction costs as a separate project and a separate investment recovery.

Estimate annual ownership and operation costs for the planned production capability or throughput.

Calculate amortization of the factory capital costs and operation costs for recovery over the planned production quantity and express them as a percentage overhead cost relative to shop labor.

Price all components manufactured at the factory inclusive of shop overheads with the amortization component.

Price without mark-up all process equipment and materials that will be built into the factory modules.

6.7.2 Fuel Fabrication Plants

When estimating costs for fuel fabrication plants, team should:

Size fuel fabrication facilities to meet the projected fuel needs for the reactor concept and the nominal fleet size of 32 GW of plant capacity, and use similar processes to estimate the capital construction costs of the fuel fabrication plant.

Separate estimates of the annual operating costs and production capacity should provide input to a separate cost model to calculate levelized unit fuel cost (LUFC), including return on the investment.

The resultant costs should provide the fuel cost component to calculate LUEC for the power plant. The first fuel load may be required before commercial operation of the dedicated fuel fabrication facility; therefore, the cost may be significantly higher if fabrication is a manual process.

6.7.3 Fuel Reprocessing Plants

A fuel reprocessing plant has 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 should provide input to a separate cost model to calculate levelized unit reprocessing cost (LURC), including return on the investment. The resultant costs should provide the fuel reprocessing cost component to calculate LUEC for the power plant.

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7. TOTAL CAPITAL AT RISK

This chapter provides the guidelines to estimate TCIC of a nuclear 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 are the starting point for costs developed in this chapter. Estimating teams should calculate the TCIC in January 2001 constant dollars. These guidelines exclude cost estimation inflation and escalation. This chapter discusses cash flow, IDC, contingency, TCIC calculations, and the cost component of the LUEC.

7.1 Cash Flow

If possible (most likely for bottom-up estimates), estimating teams should determine cash flow (funding) requirements during the design, construction, and start-up period on a quarterly basis (four schedule increments per year) for the prototype, FOAK, and NOAK plants. For concepts without enough detailed engineering and scheduling information to report cost data by quarters, estimating teams should report annual cash flows or explicitly apply a generic (e.g., "S-curve") cumulative distribution to the TCIC. The cash flow and overnight costs should be expressed in 2007 constant dollars, and teams should indicate whether contingency costs are included. Estimating teams should explicitly include contingency costs in the cash flow data if contingency cash flow is not assumed to be directly proportional to base construction cost cash flow. Time effects, such as escalation, should not be included in the cash flow because estimates should be prepared in constant dollars.

7.2 Interest During Construction

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 U.S., 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, estimating teams should calculate IDC at both 5% and 10% (see IEA and NEA, 1998).

Estimating teams should calculate constant dollar interest using the cash flow summaries developed following the guidelines in Chapter 6 and capitalize all interest costs up to the commercial operation date using the following method:

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

where

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

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

$$\mathrm{IDC}_{\mathrm{total}} = \frac{pre-contingency\ \mathrm{cost} + \mathrm{contingency}}{pre-contingency\ \mathrm{cost}} \text{ x } \mathrm{IDC}_{\mathrm{base\ cost}}.$$

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 because the discounting process automatically accounts for interest charges. IDC on equipment and facilities related to non-electrical energy products should 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, three contingencies should be considered: base cost, schedule, and performance.

7.3.1 Contingency on Overnight Cost (Account 59)

This contingency is an allowance applied to the base cost (sum or all items/activities in level one of Accounts 10 thru 50). 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 multiplied 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 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 Financial Costs (Account 69)

Cost overruns for many projects are caused by construction schedule slippage, which causes an increase in both base and financing (interest) costs. Because it is too early to have detailed construction schedules for Generation IV projects, 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 and Hudson, 1989). The EMWG suggests the application of a contingency factor to the IDC to represent the cost effects of schedule uncertainty (see Appendix A).

7.3.3 Contingency on Reactor Performance

Performance underrun 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 CF 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) should be calculated to reflect this concern (see Appendix A).

7.4 Total Capital Investment Cost

The TCIC, 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 are expressed in constant money:

$$\text{TCIC} = (\text{OCC}) + (\text{CFC})$$

Where possible, estimating teams should express all costs in constant dollars and separate them into nuclear-safety-grade, industrial-grade, and total cost in the more detailed accounting. Estimating teams should use the format in Table 7.1 to report TCIC.

Table 7.1 Total capital investment cost estimate reporting format

COA Number	COA Title	Nuclear-Safety-Grade Cost	Industrial-Grade Cost	Total Cost
10	Capitalized Pre-Construction Costs			
20	Capitalized Direct Costs			
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 on Direct Costs			
	Total Direct Cost (DCC)			
30	Capitalized Indirect Services Costs (CIC)			
	Base Construction Cost			
40	Capitalized Owner's Costs (COC)			
50	Capitalized Supplementary Costs			
	Total Overnight Construction Cost (OCC) Total Specific ($/kWe)			
60	Capitalized Financial Costs			
	Total Capitalized Investment Cost (TCIC) Total Specific ($/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 ($/MWh)
FCR	=	constant dollar fixed charge rate
TCIC	=	total capital investment cost in constant dollars ($)
E	=	annual electric energy generation for single unit (MWh/year).

An FCR is normally used to account for return on capital, depreciation, interim replacements, property tax, and income tax effects and is discussed in detail in Appendix B of Delene and Hudson (1993). The FCR can be calculated using the NECDB (ORNL, 1988) methodology as implemented in an IBM-type PC code (Coen and Delene, 1989). Because Generation IV cost estimation tax and depreciation considerations are being ignored at present, the constant dollar FCR 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 %)
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 converted 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.

The GIF guidelines use 5% and 10% real rates of return because these rates represent 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 quality assurance standards. Other unit cost components are lower, especially for that of fuel, because nuclear energy plants produce a large amount of energy from a very small volume. This amount differs from fossil plants, where fuel is usually the dominant unit cost component.

References

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8. FUEL CYCLE COST

These *Guidelines* recommend the levelized lifetime cost methodology, described in Section 9, to estimate the total levelized unit electricity cost (LUEC). Adopting the same levelized approach for the fuel cycle cost component of the LUEC ensures modeling consistency. This technique is the method usually adopted for calculating fuel cycle costs of Generation II-III+ reactors, which are now commercially deployed. In that case, the fuel cycle cost modeling essentially simulates the manner in which fuel cycle services and materials are procured by the utility or the finished fuel assembly commercial provider. This time-dependant levelized cost approach, described in Section 8.1, may be used for estimating fuel cycle costs for some advanced systems, such as sodium-cooled fast reactors (SFRs) using oxide fuel, for which some fuel cycle infrastructure, e.g., fast reactor oxide fuel fabrication, is available now – or was available in the past – providing information on unit costs and fuel cycle lead times.

For most Generation IV systems, fuel cycle details are unknown and fuel cycle infrastructure non-existent. Therefore the approach selected in G4-ECONS is the simplified "unit cost x annual mass flow" approach which estimates average fuel cycle costs at equilibrium. This method, described in Section 8.2, does not require input data on fuel cycle lead times or any time-dependant data.

Furthermore, unit costs are seldom available for advanced fuel cycles. The method adopted in G4-ECONS for costing fuel cycle services not available commercially is described in Section 8.4. It is based on the approach described in the present *Guidelines* for estimating GEN IV reactor capital cost and LUEC.

8.1 The Standard Levelized Cost Calculation Method

The levelized cost approach is a standardized technique which reflects the effect of the time value of money. This approach, which was adopted in the NEA studies on economics of the nuclear fuel cycle (NEA, 1994), recognizes that the cash out-flow for fuel cycle material and services begins before the reactor starts to generate electricity and continues well after the reactor ceases operation. It is well adapted to situations when the fuel requirements over time, including first core and reloads, are well-defined, as well are the technical requirements and specifications for the fuel In this approach, the economics of the fuel cycle is in part determined by the timing of the procurements for the various materials (such as U-ore) and services (such as uranium enrichment and fuel fabrication).

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 should be provided by system development teams; if possible these quantities of material and services should 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.

Assuming that, at equilibrium, fuel cycle requirements and performance can be averaged over the economic lifetime of the plant, the levelized fuel cycle cost can be calculated using the following formula:

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

where

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

8.2 The "Unit Cost x Annual Flow" Method Adopted in G4-ECONS

When the development of G4-ECONS began, it was realized that the amount of detailed fuel cycle information available from the Generation IV development teams likely would be very small. In some cases all that might be available would be definition of the fuel material, its enrichment, projected burn up or cycle time, and total fuel mass for an assembly or the entire reactor core. Many steps in some advanced fuel cycles, particularly those that involve fuel recycle or actinide partitioning and transmutation, are not commercially available. For such systems, new fuel cycle facilities involving new processes will have to be designed, built and operated. Therefore, no information is readily available on prices, process losses, timing of purchases, or optimum facility size for many steps.

In the context of the United States, the same problem was encountered in the Advanced Fuel Cycle Initiative (AFCI) Program and in the Global Nuclear Energy Partnership (GNEP) into which AFCI has evolved. It became apparent that the best option for both GIF and the AFCI program was to develop "snapshot-in-time" models based on projected fuel material balances for the nuclear systems of interest. The modeler could, for example, take an "equilibrium" cycle and divide it up into definable fuel cycle steps for which unit cost information was available or derivable. Figure 8.1 shows the interconnected and definable steps defined by AFCI.

Figure 8.1 shows in modular fashion the list of fuel cycle steps from which nearly any type of reactor fuel cycle can be constructed. Open, partially closed, totally closed, and fuel cycles including partitioning and transmutation can all be constructed from constituent modules. For the AFCI/GNEP work, each module is given a designated letter for identification.

Working backwards and forwards from the reactor module (R1 for thermal reactors or R2 for fast reactors) the necessary front-end and back-end fuel cycle steps are identified and a material balance developed for each step depending on the annual mass flow requirements from the previous (in terms of flow directionality) step. In order to keep the model simple, material losses between steps are ignored, recognizing that since most nuclear materials have high value these losses tend to be minimal or the materials are recycled internally within a step. Once the annual flow passing through a module or "box" is quantified, it is multiplied by the unit cost of that the material or service provided by the module to obtain an annual cost for that step.

Figure 8.2 shows how all the relevant annual costs for the required steps can be summed and then divided by the amount of electricity produced by the reactor to obtain an average mills/kWh or $/MWh levelized fuel cycle cost.

Figure 8.1 Fuel cycle modules/steps constituting a fuel cycle cost model

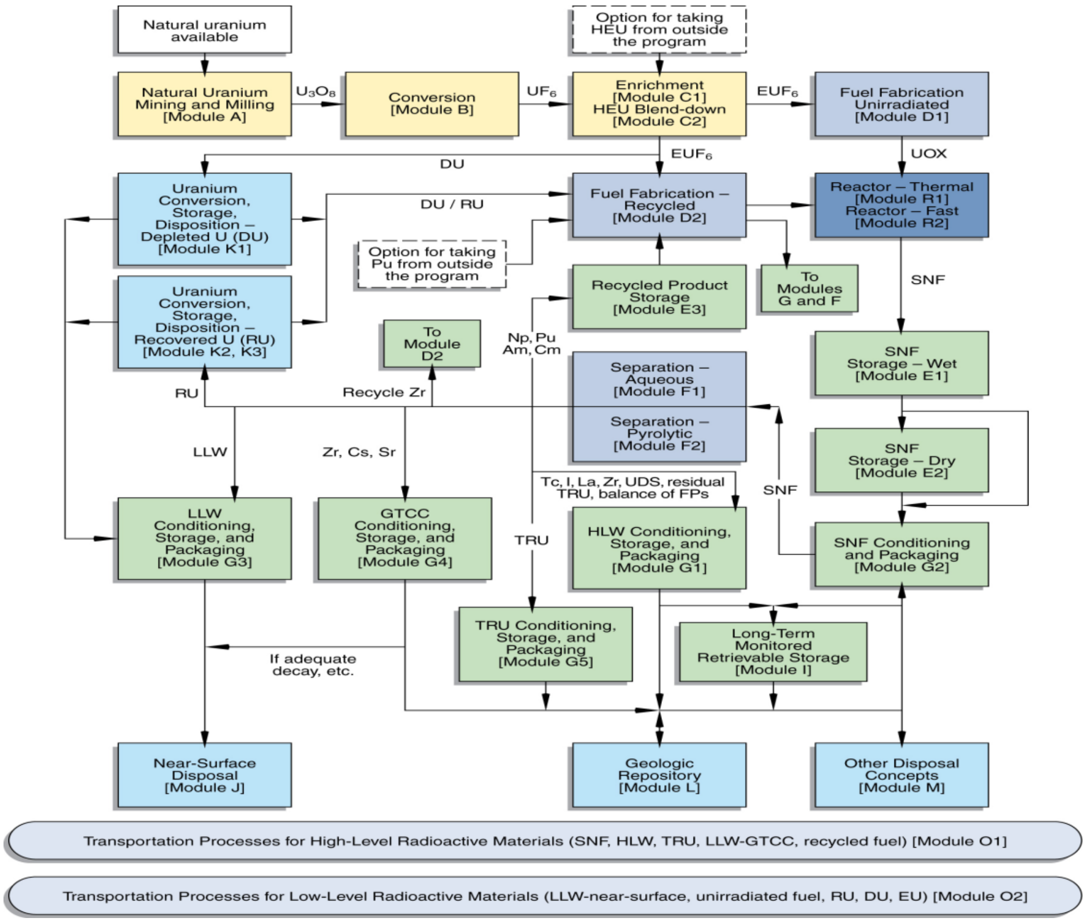
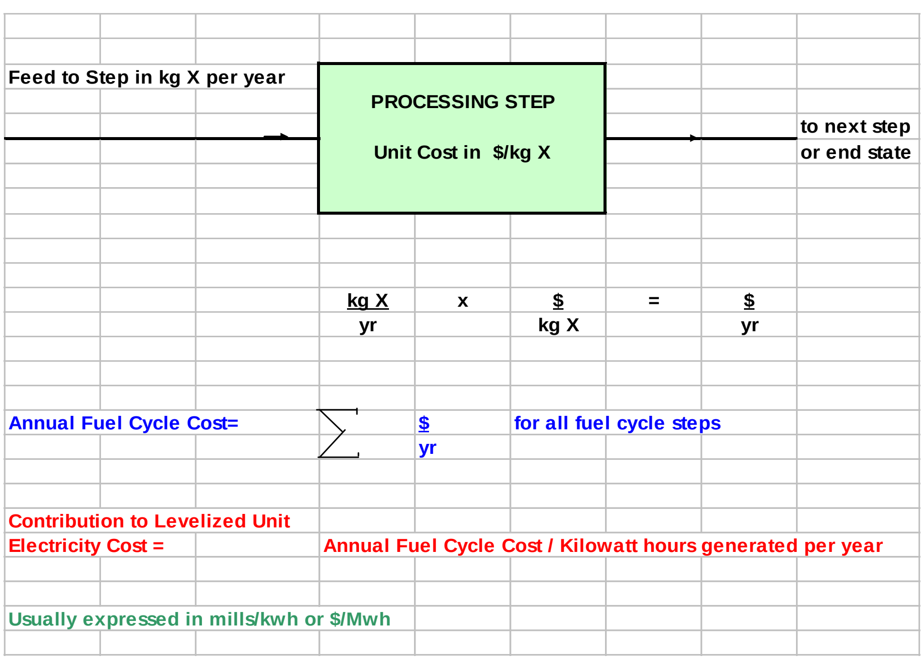


Figure 8.2 Simplified algorithm for fuel cycle cost calculation



Regardless of the type of model used the unit cost factors ($/kg of material or unit of service) that are required for the model and addressed in this chapter depend on the following factors:

Fissile/fertile materials used (natural uranium, low-enrichment uranium, highly enriched uranium, mixed oxide fuel, uranium-thorium, etc.)

Enrichment of the fuel in fissile materials

Other materials used in the fuel assemblies (zirconium, graphite, etc.)

Services required to produce the needed materials (mining, milling, conversion, enrichment, fabrication)

Costs of spent-fuel disposal or reprocessing and waste (including low-level, high-level and transuranic waste) disposal.

Section 8.3 provides guidance on estimating unit costs for commercially available materials and fuel cycles. It refers extensively to the AFCI 2007 report and database on process and cost information covering all of the fuel cycle steps shown on Figure 8.1 (INL, 2007), available on the Idaho National Laboratory Publications website together with an economic sensitivity analysis report documenting the use of the data for comparison of some fuel cycles.

The availability of infrastructure to produce the fuel is a key driver of fuel cycle unit costs. When the infrastructure does not exist, the EMWG recommends assuming for costing purposes that fuel cycle facility capacities to be built will have a size adequate for fuelling a 32 GWe fleet of the Generation IV system to be supported. At this level of production capacity it is expected that competitive economics based on process learning and experience will have been realized. The calculation of projected unit costs from such, presently non-existent, facilities is discussed in Section 8.4.

8.3 Costing of Commercially Available Materials and Fuel Cycle Services

The following paragraphs give an overview of the costs of the different commercially-available 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 US study on trends in the nuclear fuel cycle (AFCI, 2007). Most of the year-2007 ranges discussed below come from the March 2007 version of this US AFCI document.

The very low natural uranium prices prevailing in the late 1990s and early 2000s created economic difficulties even for the very best mines. While a continued supply of uranium from materials declared excess to national security by Russia and the United States maintained prices at low levels in the early 2000s, a rebound of demand for newly mined natural uranium, as a result of draw-down of inventories and other market factors such as an anticipated "Nuclear Renaissance", led to increasing spot and long-term contract prices. Spot prices were multiplied by 3 to 4 between 2003 and the middle of 2007, reaching at their peak nearly 140 $/lb U_3O_8 but dropped rapidly to less than 90 $/lb U_3O_8. A long term price range of 10 to 90 $/kgU with a most likely value of around 60 $/kgU (i.e., around 23 $/lb U_3O_8 is felt to define a reasonable distribution for the ore cost over the next 30 years given a reasonable increase in world nuclear capacity.

The conversion market, in essence based on chemical processes, has experienced a period of decreasing prices during the same period (late 20th century-2002) as uranium ore. Like uranium, conversion has seen a surge in price since 2003, but not with the same multiplier. The present spot price for conversion of natural uranium oxide to uranium hexafluoride for enrichment lie in a nominal range of 9 to 12 $/kgU, a significant increase over the spot prices in 2000 (reported by NUKEM) in the range of 2.5 to 4 $/kgU. In the longer term, a range of $5/kgU to $15/kgU with a most likely cost of $10/kgU may be expected (AFCI, 2007).

In the last two decades of the 20th Century the enrichment market saw significant changes and until 2003 was characterized by persistent over-capacity, resulting in a ”then” price range of about 80 to 100 $/SWU. For the same reasons as for U-ore and conversion, the enrichment market has seen a recent up rise with spot prices in the $120/SWU to $140/SWU range. As with U-ore, this price increase may be temporary. As more efficient gas centrifuge technology takes over, production costs and prices should decrease. A range of $100/SWu to $130/SWU with a mean of $105/SWU should be reasonable for fuel cycle analysis purposes (AFCI, 2007).

Existing excess capacities in a highly competitive late 20th century market led to a drastic decrease in the UOX fabrication price, currently in a range between 200 and 300 $/kgU. As with ore, conversion, and SWU, the “nuclear renaissance” is expected to have some upward push on fabrication process, but at a much smaller “multiplier” than the other front end services/materials. Since fabrication contracts are not publicly reported, it is difficult at this point to determine if this is indeed the case. A range of $200/kgU to $300/kgU with a most likely cost of $240/kgU is felt to be reasonable for U.S. PWR fuel. A range of $250/kgU to $350/kgU with a most likely cost of $290/kgU is reasonable for U.S. BWR fuel. European and Far Eastern fabrication prices are reportedly higher.

With respect to the future changes in 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, and effects resulting from mergers of suppliers (e.g., reduction of excess capacities). Fuel assembly design and fabrication also influence the specific costs of the other steps in the fuel cycle and, being the link between fuel cycle and nuclear power plant may influence the remaining elements of the energy generating costs as well.

At the end of the 20th century costs for interim storage of spent UOX-fuel (SNF) were reported ranging from 40 to 80 $/kgU, where an interim storage time of 2 years is standard. Another source reports a cost for “away-from-reactor” wet storage of LWR fuel assemblies (in 1987$) 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). Because of delays in repository and reprocessing programs, it is likely that spent LWR fuel will have to be stored for longer periods, perhaps even decades. Wet storage could add $100/kgHM to $500/kgHM to the back end costs. Dry cask storage would probably add $100/kgHM to $300/kgHM. These latter costs include SNF conditioning and packaging.

The situation is different for reprocessing because only two main commercial vendors rely on long-term contracts with specific utilities. New contracts, making use of existing facilities, seem to indicate significant price reductions, benefiting from the accumulated experience and the amortization of much of the investment costs. In the future, new plants would benefit greatly from the large experience gained during the last decades, simplifying the plants, decreasing their size, reducing maintenance requirements, etc. If, however, selected nuclides (e.g., minor actinides) were separated, the cost could be increased relative to conventional uranium/plutonium separation. Early evaluations from the AFCI/GNEP program and the European “Red Impact” project (ICAPP, 2007) seem to indicate that this is the case.

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 different countries. Disposal of high-level waste is often claimed, by the countries that have nuclear power programs, as being too important to be left to the producers of the wastes alone and should therefore be considered a national responsibility, with the waste producers paying for proper disposal. 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 vary widely.

Important technical factors that affect costs are the size of the system, development time of the disposal project, geological medium, and barrier system chosen. Next to these technical factors, social and political issues also impact costs, affecting 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 costs have decreased significantly over the past years (NIRAS, 2000). Disposal costs are estimated to be lower than 0.2 M$/m^3 of waste packaged for disposal or less for spent UOX fuel and about 0.5 to 0.7 M$/m^3 for high-level waste (Charpin *et al.*, 2000). It is also important to consider that the volume of high-level waste 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 high-level waste is cheaper than disposal as spent fuel. Regarding spent MOX fuel, the cost depends mainly on the decay heat level because a higher 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. The 2007 Advanced Fuel Cycle Cost Basis recommends a range of $381/kgHM to $900/kgHM for spent fuel and $152/kgHM to $360/kgHM for high level waste (such as glass logs) derived from the heavy metal.

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

Parameter	Unit	Lower Bound	Upper Bound	Most Likely	Description
$Cost_{U}$	$/kg$U_3O_8$	19.2	57.7	38.5	Unit cost of natural uranium (ore mining and milling)
	$/kgU	50	150	100	
$Cost_{Uconv}$	$/kgU	5	15	10	Unit cost of conversion (U_3O_8 to UF_6)
$Cost_{Uenr}$	$/SWU	100	130	115	Unit cost of enrichment (SWU=Separative Work Unit))
$Cost_{UOXfab}$	$/kgU	220	270	240	Unit cost of UOX fuel fabrication (BWR: usually higher than PWR)
$Cost_{MOXfab}$	$/kgHM	2000	4000	3200	Unit cost of LWR MOX fuel fabrication
$Cost_{UOXrepro}$	$/kgHM	460	829	502	Unit cost of UOX fuel reprocessing
$Cost_{UOXP\&C}$	$/kgHM	50	130	100	Unit cost of UOX SNF conditioning and packaging
$Cost_{UOXstore}$	$/kgHM	100	300	120	Unit cost of SNF dry storage
$Cost_{UOXgeo}$	$/kgHM	381	900	528	Unit cost of UOX SNF geological disposal
$Cost_{HLWgeo}$	$/kgHM	157	360	311	Unit cost of vitrified HLW geological disposal
$Cost_{FR\text{-}MOXfab}$	$/kgHM	3200	5000	4000	Unit cost of FR-MOX fuel fabrication (including fertile blankets)
$Cost_{FRpyro}$	$/kgHM	2500	7500	5000	(metal fuel with pyroprocessing and re-fabrication)

* From March 2007 Advanced Fuel Cycle Cost Data (AFCI, 2007).

Table 8.1 provides 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. Over the long term, beyond 30 years, cost evolutions are likely to follow the historic trends for most commodities and services (i.e., a slow decrease in constant dollar terms). The magnitude will depend, however, on aspects related to the vitality of the nuclear industry and any new regulatory requirements imposed on nuclear fuel cycle facilities and operations. Depending on the special boundary conditions, fuel cycle costs for individual countries and the individual utilities within a country may deviate significantly from such generic figures.

8.4 Costing of Fuel Cycle Services Not Available Commercially

For some Generation IV concepts, fuel cycle cost information will be required for fuel types or fuel services that are not now commercially available. Little, if any, cost or price information is available for those fuel cycle services. When data is available from system designers and/or authoritative sources such as the 2007 Advanced Fuel cycle Cost Basis report (INL, 2007), it may be used directly. However, in most cases, the estimator will need to develop unit costs based on modeling fuel cycle facilities. A unit cost can be built from the following data:

Fuel cycle facility base and owner's costs (for capital component of fuel cycle cost).
Design/construction duration (for IDC calculation).
Contingency.
The annual production from the plant, e.g. kgHM/yr (assumed constant over life of plant).
The number of years of commercial operation (for recovery of capital).
Annual operating costs ($M/yr).
An interim replacement rate of capital (treated as an annual average cost like O&M).
The cost of plant D&D (recoverable by use of a sinking fund).
The number of years the D&D fund is to be collected.

The cost summation and levelization algorithms (described in Section 9 of this report) are much the same as for the reactor. A special version of G4-ECONS, called G4-ECONS FCF [Fuel Cycle Facility], will be available specifically to address the economics of new fuel cycle facilities. 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. As mentioned earlier, the estimator should assume a capacity of the facilities designed to service a fleet of reactors representing 32 GWe.

8.5 Fuel Cycles Explicitly Modeled by G4-ECONS

Using the methodology outlined in Section 8.2, G4-ECONS has the capability to model three "hard-wired" fuel cycles. By "hard-wired" it is meant that the program pre-determines which steps constitute the particular fuel cycle option (3 options are available), and the program automatically fills out the flowcharts/summary diagrams and displays the fuel cycle component of the LUEC. The three fuel cycle options, which are shown below, are:

Code 1: Open fuel cycle (no recycle and planned repository disposal of spent fuel). This option describes today's LWR reactor systems in the United States and can also be used for gas-cooled reactors, for which fuel recycle is less likely.

Code 2: Partial recycle (meant for thermal reactors; reprocessed U is re-converted, re-enriched, and re-fabricated to produce LWR fuel assemblies. The separated Pu is diluted with DUO_2 to produce thermal MOX fuel assemblies. The fuel assemblies produced from this single recycle mode are credited back to the fuel cycle at a unit (per assembly) value equivalent to an original virgin enriched UO_2 fuel assembly. There is also the option to store or dispose of the reprocessed uranium (REPU) instead of recycling it.

Code 3: Total recycle. This option is for fast reactor systems that operate in the high conversion ratio or breeder mode. Make-up uranium is supplied to the system to account for the fission products that are removed. There is also the option to store excess Pu produced.

It should be noted that the fuel cycle model in G4-ECONS is designed to model "one-reactor-at-a-time". It is not designed to model symbiotic systems, such as those proposed in the GNEP program, where actinide products from reprocessing of fuel from many LWRs becomes the make-up feed for a series of actinide-burning fast reactors. These cases have to be modeled with stand-alone spreadsheets/flow diagrams where the user selects fuel cycle steps from different reactor systems and integrates them manually. Flow sheets are not created automatically as is the case with G4-ECONS. The December 2006 *Advanced Fuel Cycle Economic Sensitivity Analysis* report shows two cases (single tier thermal and fast recycle of actinides) where symbiotic fuel cycles were modeled in order to effect thermal and fast reactor destruction of actinides.

Figure 8.3 shows the fuel output from G4-ECONS for an open cycle. The example reactor is a Generation III+ ABB-CE System 80+ design for which cost and fuel cycle material balance information was available. The unit cost values selected for input are the "most-likely" values from the 2007 Advanced Fuel Cycle Cost Basis Report. Most of these values also appear in Table 8.1. The reactor is assumed to undergo refueling every 18 months and has a fuel burn up of ~47,000 MWd/tHM. It should be noted that G4-ECONS has an internal enrichment calculator in order to calculate the separative work (SWU) requirements to produce EUO2 fuel of a specified U-235 content. The program can also automatically find the optimal tails assay which minimizes the cost of EUF6 to the front end of the fuel cycle. The repository cost can be entered in terms of $/kgHM or in mills/kWh. For the burn up shown in the diagram below, a 1 mill/kWh waste fee would translate to just under $400/kgHM. The ultimate long-term cost of repository spent fuel disposition is still a major unknown.

Figure 8.4 represents "Fuel Cycle Code 2", where the LWR fuel is assumed to be reprocessed, in this case by a PUREX system, and the separated REPU and Pu are utilized to produce energy-equivalent fuel assemblies which can displace EUO2 assemblies. In this "partial recycle" mode, which assumes one-time-only use of the recycled MOX/REPU assemblies, approximately 20% of the original EUO2 number of fuel assemblies reloaded are returned for credit as recycle assemblies. This cycle is sometimes called "MONOMOX" since the MOX is assumed to undergo only one recycle. In the case shown the front end of the fuel cycle is nearly identical to the open cycle in Figure 8.1. This partial recycle option also has a switch that can be activated to store or dispose of the reprocessed uranium instead of recycling it. There are also costs associated with these paths. Again, the input unit costs are taken from the July 2007 *Advanced Fuel Cycle Cost Basis Report.*

Figure 8.5 shows the schematic for a nearly totally closed fuel cycle, i.e. Fuel Cycle Code 3. The reactor and fuel cycle information were supplied to the Generation IV EMWG by its Japanese participants. The reactor is a large sodium-cooled fast reactor utilizing (Pu,U)O2 MOX fuel. The reactor is called the JSFR or Japanese Sodium-cooled Fast Reactor and represents the major development item in the Japanese Generation IV program. This reactor is a heterogeneous system, hence drivers and blankets are utilized. In the G-4 ECONS representation, however, the uranium in the blankets is combined with the Pu and U in the driver fuel for purposes of analysis. Aqueous reprocessing of fast reactor drivers and blankets is assumed. Depleted uranium is supplied to the fuel fabrication facility as makeup to the overall recycle system. The unit costs used in the Figure below were provided by Japanese members of the EMWG. It should be possible to run similar cases for other fast reactor systems such as the PRISM system being proposed by General Electric in the US.

Future efforts in G4-ECONS fuel cycle modeling will be oriented toward creating a fuel cycle specifically oriented toward actinide burning, where lower fast reactor conversion ratios will be needed. It will also be necessary to modify the closed cycle model such that drivers, blankets, and targets can be accounted for separately. The European "Red Impact" program is also considering actinide burning, and partitioning and transmutation cycles using a methodology similar to that described in this chapter (Lauferts, 2007).

Figure 8.3 G4-ECONS fuel cycle model – example flowchart for an open cycle

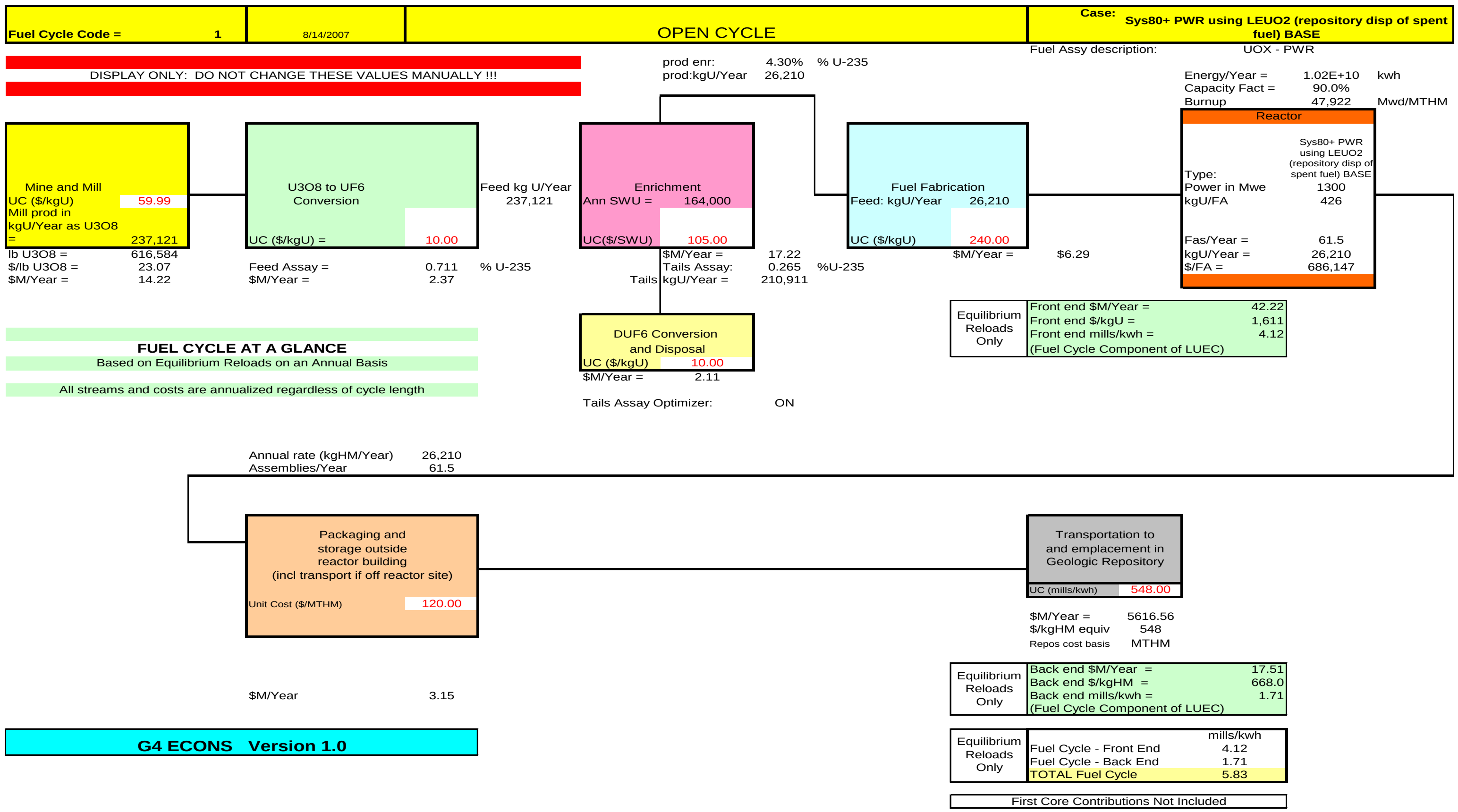


Figure 8.4 G4-ECONS fuel cycle model – example flowchart for a partially closed fuel cycle

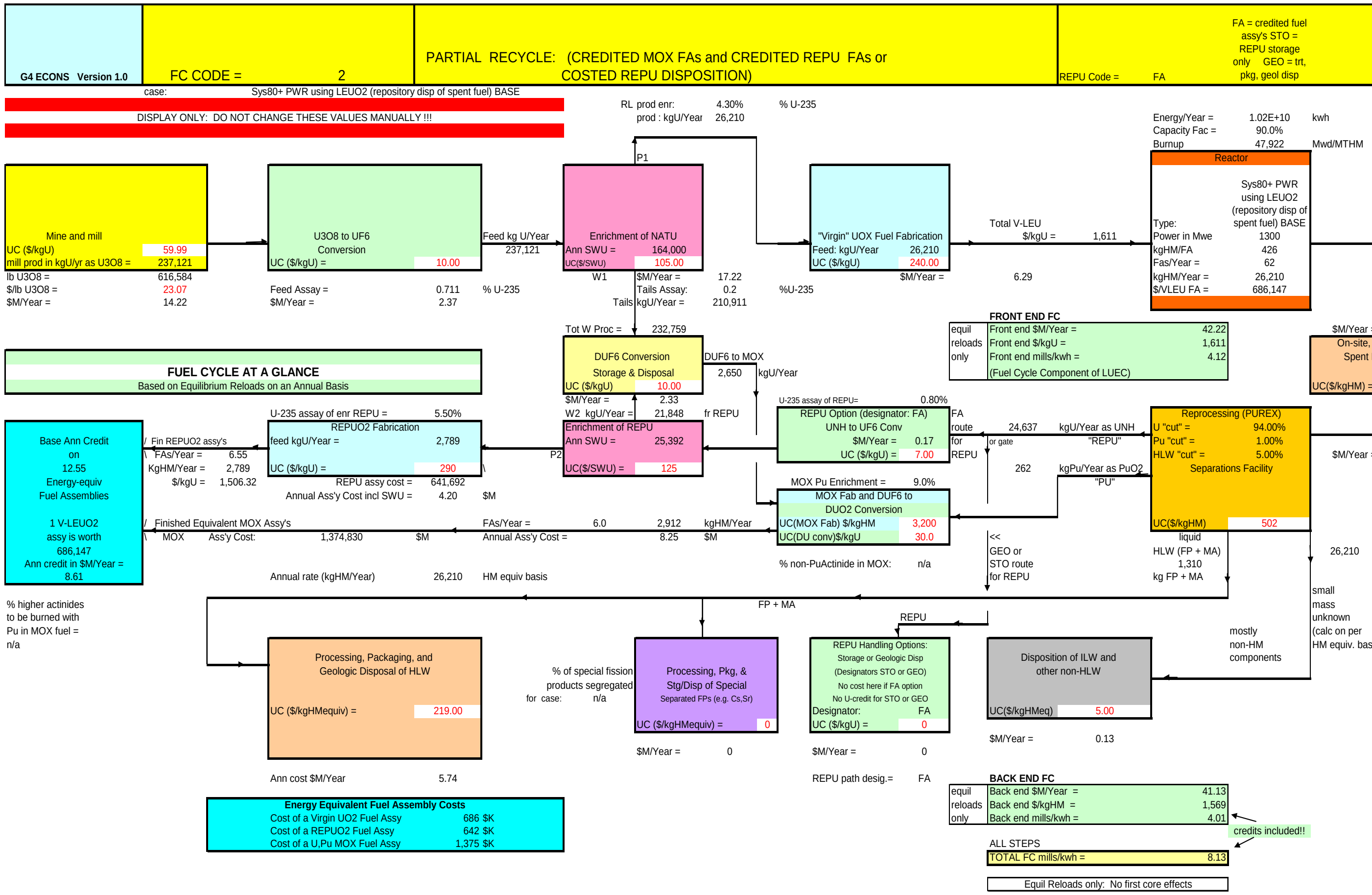
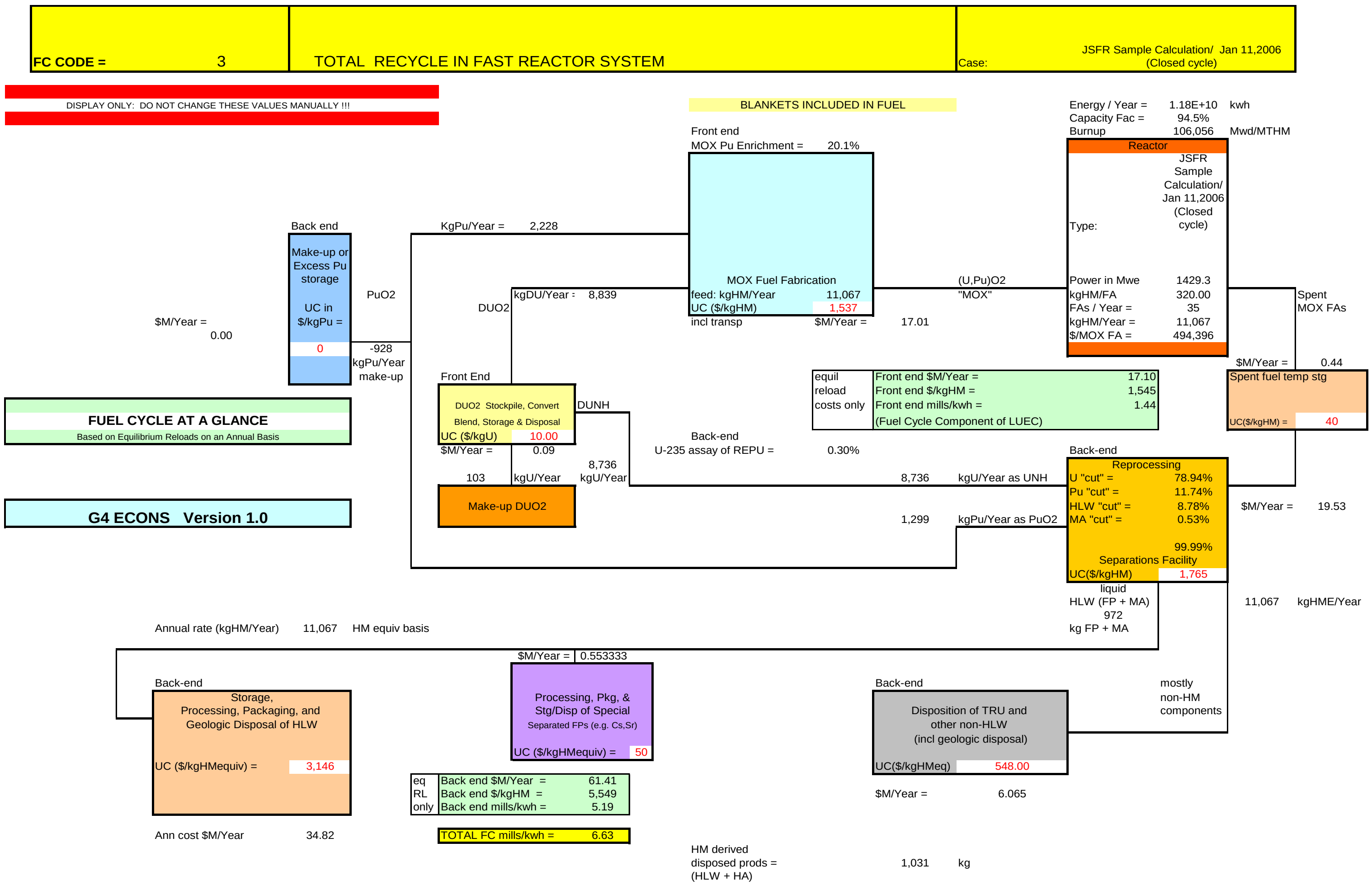


Figure 8.5 G4-ECONS fuel cycle model – example flowchart for a totally closed fuel cycle



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9. CALCULATION OF LEVELIZED UNIT ELECTRICITY COSTS

This chapter discusses O&M and D&D costs and how they are included in the calculation of the LUEC. Levelization divides the annual costs of operation over total annual production, allowing comparison with other electricity-generating technologies. The LUEC 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 four primary components of the LUEC are (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 as part of the TCIC of nuclear energy systems, within O&M costs, or as a separate category; the last approach is 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 in the period t
$FUEL_t$	=	annual fuel expenditures in the period t
$O\&M_t$	=	annual O&M expenditures in the period t
E	=	annual production in the period t
R	=	discount rate

Assuming constant annual expenditures and production, adding the cost of D&D to levelized annual expenditures ($\Sigma\ [I_t\ (1 + r)^{-t}\ [/\Sigma\ [E_t\ (1 + r)^{-t}]$) to obtain the levelized cost of capital (LCC), the formula becomes:

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

9.1 Operations and Maintenance Costs

This subsection provides guidance on 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. Estimating teams should add these variable costs to the fixed costs, which are independent of generation, to arrive at a total annual O&M cost. Because a fixed amount of electricity generation per year is assumed, both fixed and variable costs should 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. Report site staff requirements as shown in Table 9.3. For multi-unit plants, estimating teams should specify the annual O&M costs and staffing requirements for each unit and staffing requirements not associated with a specific unit ("common").

Table 9.1 Annualized operations and maintenance Code of Accounts description

GIF COA Number	Description
71 Operations and Maintenance Staff	Includes all O&M personnel assigned to the plant site. See Table 9.3 for typical categories.
72 Management Staff	Includes all management personnel assigned to the plant site. See Table 9.3 for typical categories.
73 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 71 and 72 above.)
74 Operations Chemicals and Lubricants	Can consist of a mix of variable and fixed costs. Includes non-fuel items such as resins, chemicals, make-up fluids. Includes costs of management and disposal of operational radioactive waste.
75 Spare Parts	Purchased spare parts for operations of plant.
76 Utilities, Supplies, and Purchased Services	Consumable 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".
77 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.
78 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.
79 Contingency on Annualized O&M Costs	Allowances for contingency costs for the desired confidence level of O&M costs.

Table 9.2 Sample annual operations and maintenance cost format for multi-unit plants

Direct Power Generation	2007 $/year			
	1st Unit	2nd Unit	Other Units	Common
71 O&M Staff				
72 Administrative Staff				
73 Salary-Related Costs				
74 Operation Chemicals and Lubricants				
75 Spare Parts				
76 Utilities, Supplies, and Purchased Services				
77 Capital Plant Upgrades				
78 Taxes and Insurance				
79 Contingency on Annualized O&M Costs				
Total Annual O&M Costs				

Table 9.3 Sample nsite staff salaries and requirements

Category	Salary 2007 $/year	Number of People		
		1st Unit	2nd Unit/Other	Common
72 Plant manager	174 100			
Administrative Division				
72 Manager	121 200			
72 Environmental control	77 000			
72 Emergency plant public relations	77 000			
72 Training	84 200			
72 Safety and fire protection	71 400			
72 Administrative services	46 200			
72 Health services	46 200			
72 Security	41 600			
72 Subtotal				
Operations Division				
71 Manager	121 200			
71 Shift supervision	89 400			
71 Shift operators	75 000			
71 Results engineering	75 000			
71 Subtotal				
Maintenance Division				
71 Manager	121 200			
71Supervision	82 900			
71Diagnostic engineering	75 000			
71 Crafts (Mech., Elect., etc.)	58 900			
71 Annualized peak maintenance	58 900			
71 Annualized refueling	63 700			
71 Radwaste	58 900			
71 Quality assurance	63 700			
71 Planning	63 700			
71 Grounds and housekeeping	42 000			

Category	Salary 2007 $/year	Number of People		
		1st Unit	2nd Unit/Other	Common
71 Warehouse	54 300			
71 Subtotal				
Technical Division				
Manager	121 200			
Reactor engineering	89 400			
Radio and water chemistry	82 900			
Licensing and reg. assurance	76 500			
Engineering	76 500			
Technicians	62 200			
Health physics	64 000			
Subtotal				
Total staff				

The O&M cost estimate should be the most likely cost and should be expressed in constant dollars for the reference year (i.e., January 2007). Some O&M costs are design independent and/or owner related. Data for these factors are provided below (Table 9.3) and should be used in the development of the annual O&M costs.

Tables 9.1, 9.2, and 9.3 are based on U.S. practice and represent what should be included in a bottom-up cost estimate. Some O&M categories shown may not apply to some Generation IV systems or in countries outside the U.S. International GIF members should modify the guidelines 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 (percent of base cost experienced per year) can be assumed and expressed in $M/year.

Table 9.3 shows annual onsite staff salaries in the U.S. with an additional allowance (e.g., 15%) for social security tax and unemployment insurance premiums. For offsite technical support, an average annual salary of $89 000/person (2007$) should be assumed, with an additional 70% added to the total (social security tax and unemployment insurance and a 60% overhead allowance for office space, utilities, and miscellaneous expenses). These onsite and offsite staff salaries are the same as shown in Delene and Hudson (1993) but adjusted for inflation from 1992 to 2007 using the Bureau Labor Statistics Index 320. The pension and benefits account (73) that includes workman's compensation insurance should be calculated as 25% of the sum of onsite and offsite direct salaries (excluding offsite overhead). If not included elsewhere, appropriate utility overhead and G&A costs can be added to this annual salary sum to obtain a full staff labor related cost.

Annual nuclear regulatory fees in the U.S., based on information on the USNRC web site at www.nrc.gov/reading-rm/doc-collections/cfr/part171/part171-0015.html, are approximately $4 million per year (2007$) per unit.

For a top-down estimate, the level of detail above may not exist. The following representation for O&M costs should be sufficient.

Annual non-fuel O&M costs can be more simply represented in terms of a fixed and variable component. The fixed component depends on the reactor capacity and does not depend on the level of power generation. Most staff costs fall in this category. Variable costs depend on electricity production and include some non-fuel consumables. In this formulation the non-fuel O&M component of the LUEC is the sum of the fixed and variable components, calculated as follows (in mills/kWh or $/MWh units):

The fixed component may be expressed as:

$$LUECFOM = FIXOM*RXCAP*1.E6 / E$$

where

FIXOM = fixed O&M component in $/kWe
RXCAP = net power capacity of reactor or fleet in MWe
E = electricity production of reactor or fleet in kWh/year

For example, if RXCAP =1000 MWe, and FIXOM = 62 $/kWe-yr, and E = 7.9E+09 kWe-h/yr the annual fixed component would be $62M/yr or 7.85 mills/kWh. The value of $62/kWe-yr represents an average for LWRs taken from IAEA data.

The variable component LUECVOM = VAROM is expressed in mills/kWh or $/MWh. A value of 0.45 mills/kWh is typical for LWRs according to IAEA data. This value does not include levelization of capital replacements.

The total levelized non-fuel, non-capital replacement O&M cost for the reactor is thus LUECFOM + LUECVOM. For the example values above, the total O&M would be 8.3 mills/kWh. It is expected that fast reactors would have somewhat higher values for the fixed and variable components.

For either the bottom-up or top-down estimate, 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 equation assumes that each year of operation has the same constant dollar cost, OM, and annual electricity production (these are simplifying assumptions):

$$LCOM = OM/E$$

Capital replacement should be included in LCOM through its average levelized value.

9.2 Decommissioning and Dismantling 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.

9.2.1 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 were seen to vary from $300 million to $450 million.

The EMWG recommends that a typical value of $350 million (2007$) be used as the radiological decommissioning cost of a single unit of a water reactor at a nuclear energy plant. This amount does not include dismantling costs or the costs of restoring the site to unrestricted use. In addition, a default minimum cost**,** a function of unit size, has also been defined, based on the USNRC minimum prescribed decommissioning costs developed by the Pacific Northwest National Laboratory (to release the site from USNRC regulation). Separate minimum costs as a function of unit thermal output were prescribed for PWRs and BWRs. For the GIF guidelines, the previous relations were increased by the rate of inflation since 1992. The minimum cost equations are:

- 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 the design team's estimates. In absence of detailed estimates, the total constant dollar decommissioning cost should be 33% of the total direct capital cost. Estimating teams should build contingency directly into the D&D costs rather than carry it out as a separate account.

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

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

where

LDDP = the annual constant dollar payment made to the D&D sinking fund

CDD = estimated decommissioning cost in reference year constant dollars

$SFF(r, L_{econ})$ = sinking fund factor at rate r for t years, that is $SFF(r, t) = r/[(1+r)^t - 1]$

r_{real} = the real discount rate

L_{econ} = life of the plant assumed for fund accumulation.

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

$$LCDC = LDDP/E$$

9.2.2 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.

The national policies and industrial strategies adopted in decommissioning projects or assumed for cost estimation differ greatly. The resulting variability of decommissioning costs has been recognized in all international studies. However, the analyses identify cost drivers and provide reasonable formulas to estimate decommissioning costs for planning and funding purposes.

The last NEA study on decommissioning policies, strategies, and costs (NEA, 2003) showed that decommissioning cost estimates 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 assumptions of the GIF guidelines.

The study also showed that labor costs generally represent a significant share of total decommissioning costs, ranging from 20% to 40%. Two cost elements represent a major share of total costs: dismantling and waste treatment/disposal, accounting for around 30% each. Three other cost elements 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 did not 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), 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 can 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.

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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, providing general accounting guidelines and specific guidelines on allocating common costs in joint-production systems.

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 BOP 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 significantly affect the economy of each product.

10.1 General Accounting Guidelines

The following subsections provide general guidelines to calculate capitalized direct costs, other capital costs, annualized costs, and LUPC.

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 (2001), p. 77 to 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 single-digit COA codes are consistent across all plants. The two-digit codes differ only for the capitalized direct costs for Accounts 22 and 23. The three-digit codes begin to differentiate the details that are unique to each type of plant, especially the capitalized direct cost accounts within Accounts 22 and 23. Table F.1 of Appendix F provides sample tabulations of COA structures for different types of plants.

Plants that combine a reactor with facilities to produce non-electricity products 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 should be estimated using the methodology described for nuclear power plants. The project execution plan, together with project schedules and construction plans, provide the basis for estimating field indirect costs in Accounts 31 through 34. Estimating teams should provide separate detailed estimates of design and project management (Accounts 35 to 38) for the production plant in a similar way as for the electricity generation plant.

Estimating teams should also estimate capitalized owner's costs (Account 40), capitalized Supplementary costs (Account 50), and capitalized financial costs (Account 60) 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 O&M costs (Account 70), annualized Supplementary costs (Account 80), and annualized financial costs (Account 90) 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 the two-digit COA level provide input to other cost models to calculate 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 EMWG recommends the simplest method, known as the "power credit method," which has been adopted by the IAEA in the Desalination Economic Evaluation Program (DEEP) to evaluate the economics of nuclear desalination (IAEA, 2000).

10.2.1 Allocating Joint Costs of Electricity and Desalination

The IAEA DEEP 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, such as an 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 ($C_2 – E_2 \text{ x } C_{kWh}$). The cost of the desalted water is then calculated as

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

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 \$, C_{water} is obtained in \$ per m^3.

Another method – the exergy prorating method – is also discussed by the IAEA, but rejected as too complex to implement, even though all the advantages of size and resource sharing are allocated equally (and equivalently) between the power and the desalted water. 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 method is preferred 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 ($C_1 - W_1 \text{ x } C_W$). The cost of power becomes $C_{kWh} = (C_1 - W_1 \text{ x } C_W)/E$. This equation can be generalized to levelized costs (see below).

At the center of the literature on joint production is the choice of a cost between the costs estimated by these two methods. 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 and neither method guarantees an economically efficient allocation, the EMWG suggests following the power credit method implemented in DEEP to evaluate the economics of joint production.

10.2.2 Levelized Unit of Electricity Cost and Levelized Unit of Product Cost for Joint Production Nuclear Energy Systems

Following the power credit method, the first step in determining the LUEC and LUPC is to determine costs for the reference electricity-only plant:

A – Electric Power Plant

A10 – Capitalized Pre-Construction Costs	(CPC)
A20 – Capitalized Direct Costs	(CDC)
A30 – Capitalized Indirect Services Cost	(CIC)
A40 – Capitalized Owner's Costs	(COC)
A50 – Capitalized Supplementary Costs	(CSC)
A60 – Capitalized Financial Costs	(CFC)
A70 – Annualized O&M Costs	(AOC)
A80 – Annualized Fuel Costs	(ASC)
A90 – Annualized Financial Cost	(AFC)

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

In the second step, 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

D – Desalination Plant	
D10 – Capitalized Pre-Construction Costs	(CPC)
D20– Capitalized Direct Costs	(CDC)
D30 – Capitalized Indirect Services Costs	(CIC)
D40 – Capitalized Owner's Costs	(COC)
D50 – Capitalized Supplementary Costs	(CSC)
D60 – Capitalized Financial Costs	(CFC)
D70 – Annualized O&M Costs	(AOC)
D80 – Annualized Fuel Costs	(ASC)
D90 – Annualized Financial Cost	(AFC)

When the two systems share a component, the costs are split between them. For example, 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), then

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

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.

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11. ESTIMATING FACTORY-PRODUCED MODULAR UNITS

These guidelines seek to provide a standardized cost estimating protocol 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. To provide a credible, consistent basis for the estimated costs, early estimates of the evolving design concepts are expected to be based on conventional construction experience of essentially stick-built plants. This limitation is desirable from a consistency point of view because it provides a good starting point for consistent economic evaluation of the different reactor concepts. Early assessments of significant modularization benefits should be separately stated and not an inherent component of the estimate details.

This chapter addresses the challenges involved in estimating the effects of modularization on a new reactor concept especially during this transitional period of significant evolution of robotics and further automation of manufacturing processes that are fully integrated with a project design definition. The potential benefits from future manufacturing capability are significant, and an early assessment made prematurely may inappropriately skew the results of comparisons between modular and conventional, stick-built plants. The following guidelines enable some consideration of modularity benefits at this early stage and allow consistent application in the assessments by each proponent of the different reactor concepts.

The EMWG recommends that a thorough study be performed when actual manufacturing experience reflects robotics and automation integrated for similar projects beyond a standard factory-produced product. Current evolution of large commercial aircraft production techniques may provide some insight to significant cost benefits and progress.

11.1 Definitions for Estimating Modular Units

To have a clear understanding and as a basis for comparison, it is useful to correctly define commonly used terms belonging to the modular domain and thereby establish a bounding framework: See Section 1.4 Definition of Cost Estimating Terms for the following Modularization related terms:

- Construction Module
- Equipment module
- Factory (manufacturing facility) FOAK costs
- Modularity
- Modularization
- Modular unit
- Stick-built Plant

11.2 Module Cost Components

Cost summaries developed for the stick-built plant should be converted at an appropriate level of COA cost summary. The following discussion addresses each cost component and recommends guideline cost factors to be applied to convert field construction costs to factory module fabrication. Proponents should provide separate COA worksheets with supporting data for factors used in their estimates.

Each component of the cost consists of a COA, process equipment cost, materials, direct labor hours, and direct labor cost. The adjustment for the estimated field construction costs to reflect shop fabrication and modularization are described below.

11.2.1 Code of Accounts

The COA should be adjusted as follows:

Modularized plant scope should be assessed at a lower level of COA than the reporting two-digit level, at a minimum at the three-digit level. Expert judgment should be used to assess the percentage of the account code to be factory assembled and the percentage to be modularized. These percentages should be applied against the COA scope cost components with cost factors to convert the estimated field construction costs to modular plant, shop fabrication costs.

When equipment items or piping are combined with structures to produce a factory-assembled equipment module, cost estimators should prepare a worksheet documenting each module. The worksheet should identify by three-digit GIF COA the applicable items and costs that compose the module. For each three-digit account, the worksheet should 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 which 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 to 26).

11.2.2 Process Equipment

The cost of process equipment is independent of methods of plant construction and would remain the same as for stick-built plants. Responsibilities for design, order placement, and terms would also be the same. Minor differences may occur in cost of delivery, warranty, spare parts, component testing, and system testing. Process equipment costs should be segregated to facilitate subsequent top-down estimating techniques.

The cost factor to convert estimated field construction costs to a modular plant is 1.00 applied against the percentage of process equipment costs for the modularized account scope.

11.2.3 Materials

Permanent plant materials for facility construction may differ significantly if the plant is designed for modular construction. Modular designs are expected to require additional support structures for independent module integrity during fabrication shipment and installation, and some of the structural material components such as concrete may remain site-installed.

The cost factor to convert Account 21 materials to a modular plant is 1.05 applied against the percentage of material costs for the modularized account scope. This factor allows for additional structural support materials required when a single structural member passes through multiple modules.

Non-process equipment and commodities for utilities and services would remain the same as for stick-built plants. Factory installation of materials is expected to be more controlled, minimizing waste and achieving economies from supplier chain arrangements and multi-unit ordering.

The cost factor for a FOAK plant is 1.00, and the NOAK plant 0.90, applied against the percentage of material costs for the modularized account scope.

11.2.4 Direct Labor

This cost component contributes the most to the difference between the construction of a stick-built plant and a modular plant. Transfer of craft hours from the field to a shop environment has a compounding benefit on the project costs, including reducing the onsite craft labor densities and improving access and productivity of the remaining work onsite. Shop labor performs the same work in a controlled environment, which facilitates improved productivity relative to field labor and reduces the impact of weather, material handling, security, safety, waste, tools, and equipment. The direct cost per hour of construction craft labor is significantly higher than for shop labor, although the fully loaded shop labor rate may be similar or even higher when shop overheads are included. Field labor cost is further constrained by availability and skills of local labor, seasonal work, the need to recruit, temporary parking, change facilities, workshops, cranes, and other construction equipment as well as other indirect support services.

Recommended cost factors to convert direct labor to factory costs are as follows:

- Reduce direct hours by the percentage of modularized account scope, with a corresponding reduction in field labor cost. Reduce field indirect support costs and evaluate them separately for the remaining field construction scope considering the reduced direct hours of work.
- Add shop direct hours equivalent to the field reduction in direct hours multiplied by the ratio of the shop productivity factor to field productivity factor for a nuclear island and BOP scope:
  Nuclear island = 0.50 / 1.60 = 0.3125
  BOP scope = 0.30 / 1.20 = 0.2500
- Extend shop labor by the shop direct labor rate, for the U.S., $12.00/hr (Field direct labor = approximately $34.00/hr)
- Add shop overheads, including indirect labor, supervision, management, and others. Include facility costs, equipment, utilities, insurance, property taxes, and capitalization charges. Exclude allowances for extensive automation plants or robotics. Include fabrication design only with detail design of a module by others. Shop overheads equal 200% of shop direct labor cost.

11.2.5 Freight to Site

For freight to the site at a nominal distance and a nominal cost, a factor relative to total cost of the module should be allowed, including 2% of the resultant module total cost.

11.2.6 Module Cost Summary

As for all other cost entries, only the process equipment should be reported as equipment cost. Other factory cost, including shop labor and materials, should be reported as material costs in the GIF COA cost estimate format. Field labor to install a module should be recorded as site labor. Labor costs to produce and/or install a module may be prorated among the related three-digit GIF COA, if necessary. Cost estimators should document the basis for cost-related assumptions regarding the module factory. 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. The wage rates for factory craft workers should be based on the local labor data for the factory site. Any adjustments to the labor rates to reflect the factory environment, including overheads and general and administrative costs must be fully supported in the cost estimate reports. For large equipment items and modules, the site-delivered transportation costs should be identified as a line item.

For large factory equipment items, such as the reactor vessel and internals, steam generators, and heat exchangers, supporting cost data by component must be available for review, including factory material cost, material weights, factory direct labor hours, recurring cost, and total cost for each equipment item.

11.2.7 Module Installation Labor

For module installation labor, costing teams estimate task/crew/duration for receipt and installation of factory-fabricated modules and include interconnections with percentage of work scope that was not transferred from field direct to shop fabrication. For example, a typical crew of 10 for 12 days, at 8 hours per day is 960 hours should be assumed, or a direct labor cost of $33,000.

The EMWG recommends 5% as the factor relative to the direct hours of the work scope that were transferred to the shop. The example depicted in Table 11.1 shows a slight (-3%) benefit for the direct cost components. Most benefits from modularization are derived in the field indirect accounts, reduced construction schedule, and financing costs as shown in Table 11.2.

Table 11.1 Modularization cost development

Example: COA 225 - Fuel Handling, 90% Modularized $ and Hours x 1,000

Type of Plant/Component	Nuclear Island				
	P. E. $	**Hours**	**Labor $**	**Matl. $**	**Total $**
Stick-built plant	**7,718**	**20**	**682**	**6**	**8,406**
Modularized Plant					
Shop Process Equipment = $7,718 x 0.90 (% Mod)	6,946				
Field Process Equipment = $7,718 x (1-0.90)	772				
Shop Materials = $6 x 0.90 (% Mod) x 0.90 (Cost Factor)				5	
Field Materials = $6 x (1-90%)				1	
Shop Direct Labor = 20 x 0.90 (% Mod) x 0.3125 (CF) x 12/Hr				68	
Shop Overhead = 200% of Shop labor				136	
Field direct labor = (1-0.90 (%Mod)) x (20 Hrs and $682)		2	68		
Freight = 2% x (6946+5 + 68 + 136) (Shop Cost)				143	
Module installation - field direct hours 20 x 0.90 (%Mod) x 0.05 (CF) = Hours x $34.00/Hr		1	34		
Total Modularized Plant	**7,718**	**3**	**102**	**353**	**8,173**

Module / Stick-built (8,173 / 8,406) =	**-3%**

11.3 Cost Reporting Format

As for all other cost elements, common and unitized plant costs should be separated. When the design facilitates complete separation of nuclear-safety-grade areas of the plant from conventional industrial and non-safety-related areas of the plant, shop fabrication for each module may be performed to the respective standards. Shop facilities can provide the required segregation, certification, supplier qualification, and other quality assurance/quality control requirements. The productivity of shop labor is significantly improved from the field environment and, together with material handling and other support facilities, contribute to the factors described for direct labor. For safety-grade nuclear island facilities, a factor of 0.50/1.60 = 0.3125 should be used relative to field direct labor. For industrial-grade BOP facilities, a factor of 0.30/1.20 = 0.25 should be used relative to field direct labor.

See Section 4.11 for reporting format.

Table 11.2 Comparison of stick-built and modular plant features

Consideration	Stick-Built plant	Modularized Plant	% Reduction
Direct construction cost	All field construction	With shop fabrication	0-5
FOAK – NOAK Learning effect	Larger plants, less doubling of experience (8 each)	Smaller plants, larger number of plants for same capacity (32 each)	0-10
Direct labor	All field construction	Transfer to shop	30-50
Direct labor hours (productivity)	Direct hours	Reduced field work, lower worker densities, improved access	10-25
Construction/installation schedule	Regular work schedule	Parallel construction, early start fabrication, reduced field work.	30-50
Field indirect cost	Regular work schedule	Reduced field work, reduced construction schedule	30-50
Field management costs	All field construction	Reduced field work, reduced construction schedule	15-25
Direct cost contingency	All field construction	Shop safety, security, environment, seasons, support, interference, logistics, controls, etc.	10-20
Owner’s costs	Regular work schedule	Early plant start-up, factory and site	0-10
Supplementary costs	All field construction	Provisions for D & D	0
Capitalized finance cost	Regular work schedule, all field construction	Parallel construction, early start fabrication, early start operations	30-50
Robotics and automation	Minimum utilization	Future potential	30-50
Annualized costs	Regular work schedule	Designed for O&M	0-5

11.3.1 First-of-a-Kind Non-Recurring Costs

The cost factors described in this section are applicable for an existing fabrication shop without incurring specific FOAK, non-recurring costs for the facility or its equipment. Normal capital recovery costs are included in the calculations of the overhead costs. The detailed design of the modules is performed by others and only specific fabrication design details are developed by the module fabrication facility.

11.3.2 Nth-of-a-Kind Plant Module Costs

When modules are fabricated in an existing facility not specifically designed for the assembly of the plant modules, the fabrication process will improve between the FOAK and NOAK plants. The improvements will be the same as for other equipment costs contained in the FOAK plant cost estimate; therefore, a cost factor of 0.94 is applicable for every doubling of plant manufacturing experience, up to the NOAK plant.

If a dedicated factory is planned specifically to manufacture the plant modules, a separate study and resulting estimate may be made for both the FOAK and NOAK plant costs. The cost estimate for a dedicated fabrication facility may include advantages of robotics and automation.

11.4 Modularity Effects

Modularity effects include all benefits and cost differences attributed to modularization of major portions of a plant such as the following:

- **Learning effect** – Factors for adjusting FOAK plant module costs to NOAK plant module costs (see Appendix E for discussion of applicable cost factors). Unless the factory production of modules has been estimated considering all commodities at detailed unit rates for the NOAK plant, similar learning effects may be considered for the NOAK modular plant factory equipment and material costs as defined for the stick-built plant. Process equipment would be subject to a cost factor of 0.94 for every doubling of experience, and material costs would be a cost factor of 0.90 for the NOAK plant. Note that series effect, an inherent component in the definition of a standard plant, is included in learning effect.
- **Parallel production** – The required size of a module fabrication facility or requirement for multiple factories in support of the proposed commercialization plan and project construction schedules, to be defined by the estimator. Assumptions for the location of the fabrication facility and access for rail, road, and port facilities should be defined as well as data for maximum dimensions and weights of modules.
- **Parallel construction--** Module fabrication can commence in parallel with site civil work. Parallel construction reduces overall project schedule duration and cost of money.
- **Site productivity** – Improvements in productivity brought on by transfer of field direct construction labor to shop fabrication, reduction in required rework, reduction in field staffing levels, and reductions in field indirect support cost.
- **Cost of money** – The shorter project schedule reduces the cost of money.
- **Capital at risk** – Capital at risk is reduced with smaller units especially when the schedule between units is optimized to fit the power demand curve.
- **Indeterminate and contingency costs** – Controlled environment in the factory, together with improved security, decreased weather impact, and seasonal availability of labor reduces risks and improves confidence levels, requiring lower contingency cost allowances.
- **Future technology benefits** – Factory automation, robotics, and integration of all activities associated with design, procurement, fabrication, delivery, and installation, which may reduce overall plant costs if technology is maximized by a dedicated new module fabrication facility.

To maintain a common and consistent format for all reactor concepts, the EMWG recommends that a separate evaluation be made and shared by all reactor concepts, ensuring a common cost basis.

ABBREVIATIONS, ACRONYMS, & EQUATION SYMBOLS

AACEI	American Association of Cost Engineers International
A/E	Architect/engineering (firm)
AECL	Atomic Energy of Canada, Limited
AFC	Annualized Financial Cost
ALMR	Advanced liquid metal reactor
ALWR	Advanced light water reactor (III+)
AOC	Annualized Owner's Cost
ASC	Annualized Supplementary Cost
BCC	Base construction cost
BLS	Bureau Labor Statistics
BOP	Balance of plant
BPD	Barrels per day
BWR	Boiling-water reactor
CADD	Computer aided design and drafting
CDC	Capitalized Direct Costs
CF	Capacity Factor
CFC	Capitalized Financial Costs
CRF	U.S. Code of Federal Regulations
CS	Carbon steel (refers to type of pipe)
COA	Code of Account(s)
COC	Capitalized Owner's Costs
CPC	Capitalized Pre-Construction Costs
CRD	Control rod drive
CRF	Capital Recovery Factor
CSC	Capitalized Supplementary Costs
D&D	Decontamination and decommissioning
DC	Direct costs
DCC	Direct construction cost
DEEP	Desalination Economic Evaluation Program
DEPLOY	Deployment costs; true FOAK costs allocated to each unit of plant
EEDB	Energy Economic Data Base
EMWG	Economic modeling working group
EPRI	Electric Power Research Institute
FCR	Fixed charge rate
FIC	Capitalized Field Indirect Cost
FOAK	First-of-a-kind
FMC	Capitalized Field Management Costs
GA	General Atomics
GIF	Generation IV International Forum
GFR	Gas-cooled fast reactor
GW	Gigawatt
GWe	Gigawatt electric
HEU	Highly enriched uranium
HLW	High-level waste
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
IC	Indirect Costs
IDC	Interest during construction
IFR	Integral fast reactor
ILLW	Intermediate low-level waste
INEEM	Integrated Nuclear Energy Economic Model
LFR	Lead-Cooled Fast Reactor
LCC	Levelized cost of capital
LEU	Low-enriched uranium
LFR	Lead-cooled fast reactor
LLW	Low-level waste
LMR	Liquid metal reactor
LPM	Liters per minute
LUEC	Levelized unit of energy cost
LUFC	Levelized unit of fuel cost
LUPC	Levelized unit of product cost (hydrogen, etc)
LURC	Levelized unit of reprocessing cost
MHTGR	Modular High-Temperature Gas-Cooled Reactor
MOX	Mixed-oxide fuel
MSR	Molten Salt Reactor
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt hour
MWth	Megawatt thermal
NATU	Natural uranium
NE	U.S. Department of Energy Office of Nuclear Energy
NEA	Nuclear Energy Agency
NECDB	Nuclear Energy Cost Data Base
NEP	Nuclear energy plant
NI	Nuclear island
NOAK	Nth of a kind
NSSS	Nuclear steam supply system
OC	Overnight cost
OCC	Overnight Construction Cost
OECD	Organisation for Economic Cooperation and Development
O&M	Operation and maintenance
ORNL	Oak Ridge National Laboratory
PBMR	Pebble bed modular reactor
P&IDs	Piping and instrumentation diagrams
PM/CM	Project management/construction management
PCI	Power control and instrumentation
PNL	Pacific Northwest National Laboratory
POAK	Prototype-of-a-kind
PWR	Pressurized-water reactor
Pu	Plutonium

r	Real cost of money
R&D	Research and development
RD&D	Research, development, and demonstration
SCR	Sodium-Cooled Fast Reactor
SCWR	Supercritical-water-cooled reactor
SDD	System design description
SEMER	Système d’évaluation et de modélisation économique des réacteurs
SFR	Sodium-cooled fast reactor
SS	Stainless steel (pipe type)
SWU	Separative work unit
TCIC	Total capital investment cost
TFC	Total Field Cost
T/G	Turbine Generator
T-H	Thermal hydraulic
Th	Thorium
U	Uranium
UOX	Uranium oxide (fuel)
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 the development process: (1) the initial research and development effort, (2) concept development, (3) concept confirmation, (4) preliminary design, (5) detailed 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:

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. Most of the costs should 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%. (For examples of R&D concept development estimates, see *A Technology Roadmap for Generation IV Nuclear Energy Systems*, December 2002.)

Conceptual, feasibility, or simplified estimate: With technology development, the project scope and costs become more defined. Lower contingency rates (e.g., ± 30%) yield the same confidence levels or probabilities of cost overrun.

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 to identify 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.

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, 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 (AACEI, 1997) and contingencies recommended in Electric Power Research Institute (EPRI, 1993).[1] (The association of AACEI definitions with EPRI definitions is approximate.) See Parsons (1999) for similar comparisons with American National Standards Institute, the U.K. Association of Cost Engineers, and U.S. Department of Energy, Office of Environmental Management.

Table A.1 Comparison of cost estimate categories from the Association for the Advancement of Cost Engineering International and the Electric Power Research Institute

AACEI	**AACEI Expected**	**EPRI**	**EPRI Suggested**
End Usage	Accuracy Range	Designation	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 statement implies 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 $\pm X$% = ±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, σ = (X/Z) = (30%/1.28) = 23.4%. If the cost estimator had a 90% level of confidence in the ±30% accuracy range, then σ = (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

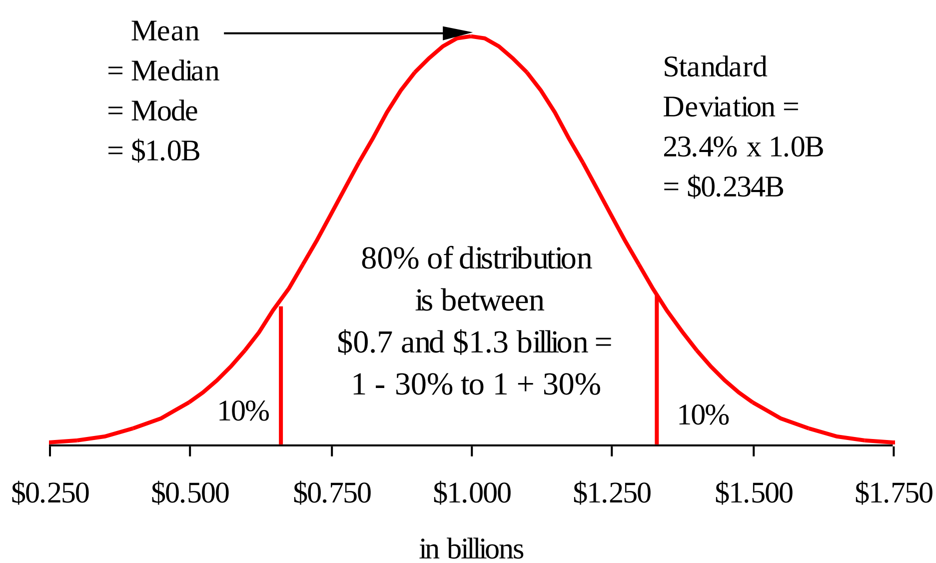

Figure A1 shows a normally distributed cost estimate with a mean, median, and mode of $1 billion and a standard deviation of $0.234 billion, or 23.4% of the expected cost. In this example, 10% of the distribution is below $0.700 (LOW) and 10% is above $1.300 billion (HIGH), yielding an 80% confidence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

- 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 A.1, 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 different medians, means, variances, and standard deviations, as shown in Table A.2. 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

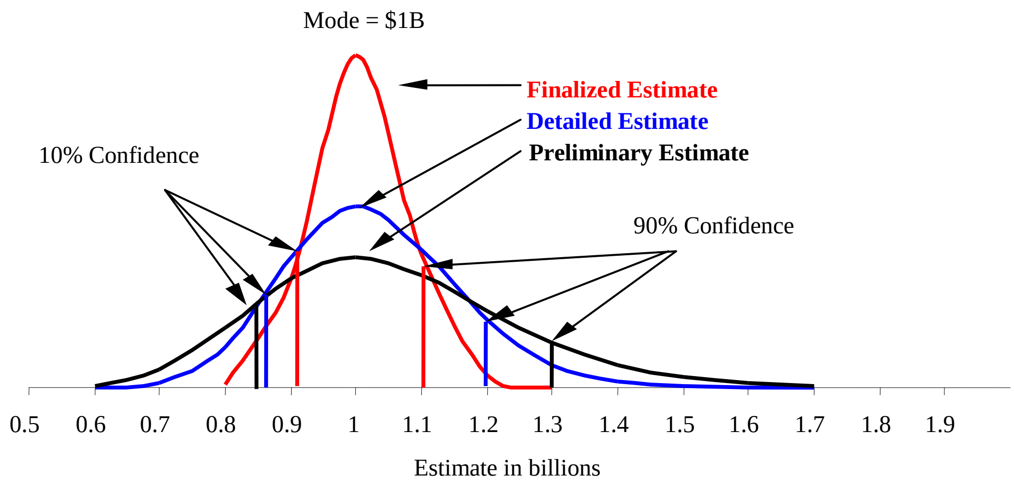

Figure A.3 Lognormal cumulative distributions for three project stage estimates

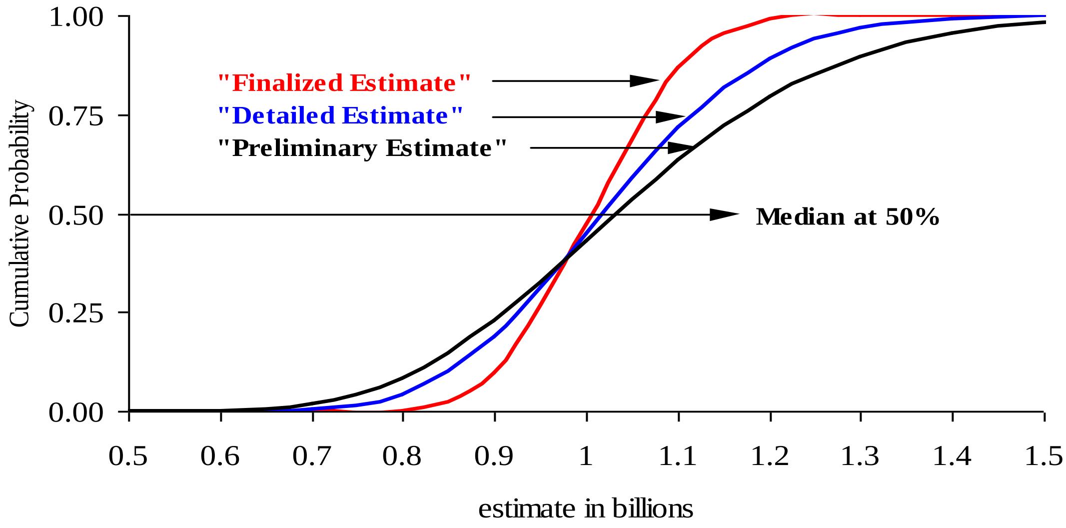

Table A.2 Medians, means, and standard deviations for lognormal estimates

Type of Estimate	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 A.2 can be adjusted to the cost estimator's confidence interval to estimate specific costs 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 Cost of Capital Estimation

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

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

where

CRF = Capital Recovery Factor, equal to $\{r\,(1 + r)^T / [(1 + r)^T - 1]\}$
BCC = base construction cost
IDC = interest during construction
E = 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 A.1 and A.2. The Total Capital Investment Cost (TCIC) is BCC plus IDC plus all associated contingencies. The following sections discuss the contingency associated with IDC, E, and LCC.

A.3.1 Estimating Interest During Construction Contingency

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):

$$\text{IDC} = \sum_{t=-LT}^{1} CX_t\ [\,(1 + r)^{-t} - 1\,] \qquad \text{(A.2)}$$

where

LT = lead time (construction duration in months) of the project
CX_t = construction expenditures in month t
r = monthly cost of capital.

This formula assumes discounting from the beginning of each period. For example, a period of 1 year 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 A.2 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 OCC is overnight construction cost (base construction cost plus contingency) in real currency (i.e., abstracting from escalation during construction). Equation A.2 becomes (with the translation of subscripts):

$$idc = \sum_{t=1}^{lt} (OC / lt) [(1 + r)^{t} - 1] \quad \text{(A.3a)}$$

$$= (OC / lt) \{[\sum_{t=1}^{lt} (1 + r)^{t}] - lt\} \quad \text{(A.3b)}$$

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 A.3b by considering the series as a uniform, present worth factor:

$$\sum_{t=1}^{lt} (1 + r)^{t} = [(1 + r)^{lt} - 1]/\mathrm{r} \quad \text{(A.4)}$$

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

$$(1 + r)^{lt} \approx 1 + \mathrm{lt} \cdot r + lt (lt - 1) (\mathrm{r}^{2} / 2) + \ldots \quad \text{(A.5)}$$

which can be substituted into Equation A.4 and simplified as

$$\sum_{t=1}^{lt} (1 + r)^{t} \approx lt + lt (lt - 1) (\mathrm{r} / 2) \quad \text{(A.6)}$$

Substituting this into Equation A.3b and simplifying:

$$idc \cong OCC[(lt - 1) \ \mathrm{r} / 2] \cong lt \cdot OC \cdot (\mathrm{r} / 2) \quad \text{(A.7)}$$

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 $1,160 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 TCIC = OC + IDC + contingencies would be $1,160M + $232M + $58M = $1,450M. 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 A.1, 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 BCC 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. 2Estimating Capacity Factor Contingency

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

$$E = CF \cdot \text{MAX} \cdot \text{Y} \quad \text{(A.8)}$$

where (1) the capacity factor, *CF*, is the percentage 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 1,350 MW (equivalent to a gross capacity of 1,400 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:

$$CF = [E /(\text{MAX} \cdot H)] \cdot (H / \text{Y}) = CU \cdot SF \quad \text{(A.9)}$$

where H is the total *generating* hours per year. The first term, $[E/(\text{MAX} \cdot H)]$, is the capacity utilization rate; *CU* is a measure of how close the plant is to potential output when it is running. The second term, (H/Y), is the service factor; *SF* is 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 SF (i.e., how much time a facility will be down for repair and maintenance). Assuming that the expected *CF* 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 CF, σ_{CF}, would be $\sigma_{SF} \cdot (1 - SF) = 23\% \cdot (1 - 90\%) = 23\% \cdot 10\% = 2.3\%$, and the contingency-adjusted CF would be 87.7% = $\text{CU} \cdot (SF - \sigma_{CF})$, 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 $\sigma_{CF} = 1.6\%$ and a contingency-adjusted capacity factor of 88.4%.

Contingency on *CF* can be set equal to $-\sigma_{CF}$, where the standard deviation 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 BCC or construction schedule estimate but 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 *CF* give reasonable values for each contingency. These standard deviations can be derived from the estimator's 80% confidence interval around the most-likely values and 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 LCC:

$$\text{LCC} = \text{CFR}(r, T) \cdot \{(\text{BCC}+\sigma_{\text{C}}) \cdot [1 + (LT + \sigma_{LT}) (r/2)]\}/ [(CF - \sigma_{CF}) (\text{MAX} \cdot \text{Y})] \quad \text{(A.10)}$$

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 CF contingency reduces LCC to \$16.93/MWh; ignoring CF and IDC contingencies reduces LCC to \$16.56/MWh; and ignoring all contingencies reduces LCC to \$14.27/MWh. In this example, BCC contingency has the greatest impact on LCC. Therefore, the greatest attention should be paid to reducing uncertainty in the BCC 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 in Table A.1.

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 *et al.* (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. However, in LOGNORMDIST, the "mean" is the natural logarithm of the median in Table A.2 and the "standard deviation" is as in Table A.2.

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

The start of Generation IV design efforts brings opportunity for cost modeling and the Economic Modeling Working Group (EMWG) cost estimating guidelines to be directly integrated into the design process. The resulting costing process uses an integrated model that unites engineering aspects (such as thermal hydraulics, nuclear core physics, heat transfer, and process control) with economics by using cost-scaling algorithms for various subsystems. (see ORNL 1988 for examples of such algorithms for reactor systems.) As an example, a costing process used by Atomic Energy of Canada, Ltd., 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) Estimate the cost of the changes
(e) Iterate back to (c) when needed vis-à-vis the targets in (a)
(f) Finalize the system concept and outline the research, development, and demonstration (RD&D) needs
(g) Conduct an 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 first-of-a-kind (FOAK) cost using actual bids/quotes as needed
(j) Confirm RD&D cost and schedule, including uncertainty and risk
(k) Establish the preliminary engineering design
(l) Estimate the design costs including Nth-of-a-kind estimates, including uncertainty and risk
(m) Estimate the cost of all product streams per assumed market(s)
(n) Iterate to (i) as needed
(o) Conduct an engineering design program for FOAK and/or prototype; complete RD&D
(p) Undertake independent review of costs with the customer(s)
(q) Establish owner's costs and define the business model
(r) Finalize cost(s) for all product streams (e.g., hydrogen, electricity, and process heat)
(s) Establish the risk, financing, contract, and project models for the build schedule
(t) Iterate to (q) as needed
(u) Prepare formal cost estimates to bid specifications using guidelines and/or conventional national practice.

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APPENDIX C. SITE-RELATED ENGINEERING AND MANAGEMENT TASKS

The following tasks relate to site-specific engineering and management:

- Prepare site-related engineering specifications and drawings (layouts, design, manufacturing, installation, and interface control drawings)
- Identify and retab 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 the 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 the safety analysis report (including emergency response) to show that the plant is identical in design
- Support vendor bid evaluations and negotiations as requested by the procurement group for releases of previously bid and committed awards
- Support the constructor in the resolution of any field problems
- Prepare site-specific licensing documents
- Repeat plant planning, scheduling, administrative, quality assurance, procurement, industrial, and public relations activities
- Provide a modularization schedule/sequencing plan
- Provide the engineering necessary to excavate and lay out the site for construction, including excavation drawings, de-watering calculations and analyses, and design and layout of access roads, parking lots, utilities, and other structures.
- Provide project management services associated with the above tasks.

APPENDIX D. SITING PARAMETERS

Siting parameters should be specified by location. In general, the following assumptions can be made about all locations:

- Soil and subsurface conditions are such that no unusual problems will be associated with soil-bearing capacity or rock removal, major cut and fill operations, or de-watering.
- 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 onsite cooling towers will be available at the site boundary.
- Construction access, construction electricity, water, telephone, police service, ambulance service, and other support services will be available near the site.

The primary purpose of defining regions is 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 guidelines from Oak Ridge National Laboratory (Delene and Hudson, 1993) defined a reference site in the Northern U.S. along with the relevant meteorological, water, seismic, soil, atmospheric dispersion, and infrastructure data. These data are no longer relevant because, under DOE partial sponsorship, utilities in the U.S. have now identified three actual existing plant sites for analysis. Unfortunately, the data are 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 information on alternative sites has been found on the International Atomic Energy Agency or National Energy Agency web sites.

The Economic Modeling Working Group (EMWG) recommends limiting assumptions on siting for U.S. sites to 0.3 g (i.e., 294 $cm.sec^{-2}$) seismic and using 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

The EMWG recommends limiting assumptions on siting for Canadian sites to 0.3 g (i.e., 294 $cm.sec^{-2}$) seismic and including the 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

The only currently available information for Asia comes from Japan, where the main steps for seismic design are defined according to the Nuclear Safety Commission of Japan (1981). At first, the facilities are classified. For class As and class A facilities, the maximum design earthquake ground motion S1 and/or extreme design earthquake ground motion S2 are evaluated. The reference for S1 is the recorded (historical) earthquake; the reference 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

The seismic requirements for the European Pressurized Water Reactor (EPR) should be appropriate. Specific parameters were not made available to the EMWG for inclusion in this document.

D.3.2 United Kingdom

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

References

Delene, J.G., and Hudson, C.R., 1993, *Cost Estimate Guidelines for Advanced Nuclear Power Technologies*, ORNL/TM-10071/R3, Oak Ridge National Laboratory, Oak Ridge, TN, U.S.

Nuclear Safety Commission of Japan, 1981, Examination Guide for Seismic Design of Nuclear Power Reactor Facilities, Nuclear Safety Commission of Japan, Tokyo, Japan.

APPENDIX E. ESTIMATING FOAK TO NOAK CAPITAL COSTS

Design teams should estimate base construction costs (BCC) as first-of-a-kind (FOAK) costs and Nth-of-a-kind (NOAK) costs. (BCC is 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 to calculate the cost adjustment factors for a nominal plant size of 1,000 MWe.

For FOAK plants (First commercial plant built with estimated equipment, materials, and labor productivity based on current or recent nuclear plant experience)

- The construction of past U.S. nuclear plants is regarded as "replica plant" experience (i.e., somewhat better than true FOAK plants).
- The marketing strategy may consider pricing of all plants, from the first commercial plant to the plant before the NOAK plant, and be levelized to recover common development, design, certification, tooling, fabrication plant recovery, and other common non-recurring costs.
- Deployment costs or true FOAK, non-recurring cost components should be identified and separately priced.

For the 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)

- NOAK costs are achieved for the next plant after 8 gigawatts (GWe) of capacity have been constructed of a particular nuclear energy system.
- Costs decline with each doubling of experience.
- A fleet size of 32 GWe should be considered to size support facilities such as fuel fabrication or reprocessing.
- The series of plants from the FOAK through the NOAK plant are 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 architect/engineering organization providing project management, engineering, procurement, and construction services. Construction will be performed by direct hire labor with subcontractors for specialty work.

The following cost factors should be considered for FOAK and NOAK plants:

- ***Construction schedule*** – The first commercial plant is most likely constructed on a regular 5 x 8s workweek schedule. Subsequent plants may incorporate accelerated construction schedules optimized to reduce plant costs inclusive of cost of money. Alternative construction workweek schedules such as rolling 4 x 10s can improve productivity by reducing staffing densities and improving material flow and work access. Alternative workweek schedules may incur premium labor costs and still produce an overall cost benefit, especially when the cost of money is included in the assessment.

- ***Construction labor*** – Learning effect has been demonstrated on many construction projects. A learning cost factor of 0.90 for every doubling of construction labor is recommended and has been used in previous cost studies. "Construction labor learning effect" includes all benefits derived from construction of a standardized plant, including 100% design before start of construction; computer models detailed for all structural commodities, services, and utilities; detailed work schedules; an optimized sequence of construction derived from previously constructed plants; detailed 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; and availability of all equipment and materials on an as-needed, just-in-time delivery basis. These practices reduce the total craft hours required to perform the same amount of work.

- ***Process equipment*** – Learning effect is also reflected in the pricing of shop-fabricated equipment, especially the non-standard equipment typical of nuclear power plants. A learning cost factor of 0.94 for every doubling of process equipment costs is recommended.

- ***Bulk materials*** – The marketing strategy of awarding multiple plant orders supports procurement of a large quantity of bulk materials with discounted pricing. Other cost studies used a 10% discount for NOAK plant orders.

- ***Field indirect costs*** – The learning effect is also applicable to field indirect costs that will experience benefits of repeat construction activities which are pre-planned through detailed daily work plans and pre-staged work packages. Indirect costs for NOAK plant construction will be reduced relative to the direct labor costs, which are also affected by learning factors. A learning cost factor of 0.97 for every doubling of plant construction costs is recommended.

- ***Operations and Maintenance (O&M)*** – O&M costs are a major component of the LUEC and historically have reduced costs because of improvements in the information technology and owner's O&M programs. Estimators should provide supporting data for any learning factors applicable to O&M costs of the NOAK plant and beyond.

Two factors drive costs: (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.

Design and certification costs, DEPLOY, are assumed to be equally distributed over 8 GWe of capacity. For example, if each unit produced 1,000 MWe, then all deployment costs would be recovered with the first eight units, such that the ninth 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 twenty-fifth unit would be free of deployment costs. Deployment cost per unit is

$$\mathrm{DEPLOY_{UNIT}} = (\mathrm{DEPLOY} \ \mathrm{x} \ \mathrm{SIZE}) / (8 \ \mathrm{GWe})$$

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 eight first 1,000-MW units, then $\mathrm{DEPLOY_{UNIT}}$ 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 follows. 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 and 2) decline at the rate equivalent to 0.94. Under these assumptions:

$$\mathrm{BCC_i} = \mathrm{DEPLOY_{UNIT}} + \mathrm{IC} + (\mathrm{DC} \cdot \mathrm{GW_i}^{\gamma}) \qquad \text{for } \mathrm{GW_i} < 8 \ \mathrm{GW}$$

$$BCC_i = CSC + (DCC \times 8^{\gamma}) \qquad \text{for } GW_i \geq 8 \text{ GW}$$

Where CSC is the capitalized supplementary costs, DCC is the direct construction cost, γ represents the "learning elasticity" and GW_i is the cumulative capacity (see IAEA, 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.

References

IAEA, 2003, *International Project on Innovative Nuclear Reactors and Fuel Cycles, INPRO*, International Atomic Energy Agency, Vienna, Austria.

APPENDIX F. GIF (GENERATION IV INTERATIONAL FORUM) CODE OF ACCOUNTS DICTIONARY

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 project management/construction management (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 Generation IV International Forum (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, and the subsystem category names should be applicable regardless of the nuclear system or technology described. Commonality of account descriptions between reactor energy systems and fuel processing and reprocessing systems is less at the three-digit level. At the three- and four-digit levels, a bottom-up estimate is usually required. 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 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 to separate and summarize costs at various levels. The structure and details are described in the following sections: Section 1, structure; Section 2, direct costs; Section 3, indirect costs; Section 4, annualized costs; and Section 5, non-electric plant codes.

F.1 Code of Accounts Structure

The full COA structure consists of components to identify and segregate costs by

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

Each item is identified by a code comprising these components. The first component is the **Unit** prefix, a number 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 the **Plant** prefix, an alphabetical character representing the type of plant, such as

A – Electric Power Plant
B – Fuel Fabrication Plant
C – Fuel Reprocessing Plant
D – Desalination Plant
E – Hydrogen Generation Plant
F – Other Process Plant.
G – Waste Repository

Where appropriate, electricity production should be considered as a primary product with allocation of common costs. Only product-specific costs for other product equipment and systems should be coded to secondary product costs, such as desalination or hydrogen production plant equipment. This approach requires Account 23 to be coded as 1A23 for a turbine generator and 1D23 for desalination plant equipment.

The third component is the **System/Facility** identifier consisting of two digits (derived from COAs in ORNL, 1988, and IAEA 2000) representing the major systems of the plant:

The first digit groups costs by type:

10 – Capitalized Pre-Construction Costs	CPC
20 – Capitalized Direct Costs	CDC
30 – Capitalized Indirect Services Costs	CIC
40 – Capitalized Owner's Costs	COC
50 – Capitalized Supplementary Costs	CSC
60 – Capitalized Financial Costs	CFC

70 – Annualized O&M Cost	AOC
80 – Annualized Fuel Cost	ASC
90 – Annualized Financial Cost	AFC

The second digit identifies costs summarized by the first digit:

10 – 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
19 – Contingency on Pre-Construction Costs

20 – 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 on Direct Costs

Accounts 10 + 20 = **Direct Costs** (DCC)

30 – Capitalized Indirect Services Cost (CIC)
31-34 Field Indirect Services Costs (FIC)
31 – Field Indirect Costs
32 – Construction Supervision
33 – Commissioning and Startup Costs
34 – Demonstration Test Run

Accounts 10-34 = **Total Field Cost** (TFC)

35-39 Field Management Services Cost (FMC)
35 – Design Services Offsite
36 – PM/CM Services Offsite
37 – Design Services Onsite
38 – PM/CM Services Onsite
39 – Contingency on Indirect Services Cost

Accounts 10 + 20 + 30 = **Base Construction Cost** (BCC)

40 – Capitalized Owner's Cost (COC)
41 – Staff Recruitment and Training
42 – Staff Housing

43 – Staff Salary-Related Costs
44 – Other Owner's Costs
49 – Contingency on Owner's Costs

50 – 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 on Supplementary Costs

Accounts 10 + 20 +30 + 40 + 50 = **Overnight Construction Cost** (OCC)

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

Accounts 10 + 20 + 30 + 40 + 50 + 60 = **Total Capital Investment Cost** (TCIC)

70 – Annualized O&M Cost (AOC)
71 – O&M Staff
72 – Management Staff
73 – Salary-Related Costs
74 – Operating Chemicals and Lubricants
75 – Spare Parts
76 – Utilities, Supplies, and Consumables
77 – Capital Plant Upgrades
78 – Taxes and Insurance
79 – Contingency on Annualized O&M Costs

80 – Annualized Fuel Cost (ASC)
81 – Refueling Operations
84 – Nuclear Fuel
86 – Fuel Reprocessing Charges
87 – Special Nuclear Materials
89 – Contingency on Annualized Fuel Costs

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

The third and fourth digits provide the lowest level of GIF code for comparisons among plants and development of reference plant costs by top-down techniques. Examples for the third digit coding for the electric power plant are discussed in the sections below.

The fourth component of the full COA structure 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 the individual-size level, (2) applying unit hour and unit material cost rates to develop the detail commodity cost, and (3) summarizing to the third digit of the GIF code. (Commodity detail codes provide further separation for structural component, size, or detailed type of commodity.)

Detailed commodity accounts consist of the following categories and commodities:

1- Concrete Category: (11) temporary formwork, (12) permanent formwork, (13) rebar, (14) embedded metals, (15) structural concrete, (16) fill concrete, (17) pre-cast concrete, and (18) concrete structural modules.

2 – Structural Category: (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: (31) reactor vessel, (32) reactor internals, (33) control rod drive components, (34) install internals, (35) install components, and (36) installation support activities.

4 – Mechanical Equipment Category: (41) turbine generator equipment, (42) condenser, (43) rotating equipment, (44) heat exchangers, (45) tanks and vessels, (46) water treatment, (47) radioactive waste, (48) miscellaneous equipment, and (49) heating, ventilation, and air conditioning (HVAC) system components.

5 – Piping Category: (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: (61) control room equipment, (62) local control panels, (64) field mounted instruments, (65) instrument supports, (66) instrumentation tubing, (63) packaged control systems, (67) control and relief valves, (68) and calibration testing.

7 – Electrical Equipment Category: (71) switchgear, (72) transformers, (73) bus duct, (74) DC equipment, (75) motor control centers, (76) other electrical equipment, (77) miscellaneous electrical equipment, (78) and switchyard equipment.

8 – Electrical Bulks Category: (81) cable tray, (82) scheduled conduit, (83) other conduit, (84) scheduled wire and cable, (85) scheduled connections, (86) and other wire and cable.

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

Using these codes, then, "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 plant equipment 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.

F.2 Direct Costs

In the GIF COA system structure, the 20 series is reserved for the direct costs of construction (i.e., the onsite labor, materials, and equipment). The IAEA account system (IAEA, 2000) does not include labor in the 20 series of accounts but included labor-hours in an indirect account. For the GIF COA, labor is included 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, architects and engineers (A/E), reactor-vendor home office staff, or construction services staff. These workers are included in the "Support Services" Accounts 30. Subcontract cost and labor should be included in the 20 series if they are for the direct scope of work. Craft labor providing common support of construction such as temporary lighting, warehousing, and cleanup is included in Account 31, Field Indirect Costs.

At the two-digit level (COA 20), this GIF 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) indicate where the more detailed cost items should be grouped. The three-digit definitions are as generic as possible, although most are based on the pressurized-water reactor (PWR) COA dictionary in the original Energy Economic Database (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., Account 25, Heat Rejection System). Annex I of the IAEA document (IAEA, 2000) gives a "dictionary" of accounts at the three-digit level (nearly 30 pages long) and differs somewhat from the U.S. (ORNL, 1988) practice in the abbreviated three-digit definitions below. At the two-digit level, all 20 accounts match the modified IAEA account system.

<u>Account 10 – Pre-Construction Costs (CPC)</u>

Account 11 – Land and Land Rights: This account includes the purchase of new land for the reactor site and land needed for any co-located facilities such as 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). (This account is not in the IAEA account system but is included in EEDB Account 20; the EMWG decided to retain this scope in new Account 11).

Account 12 – Site Permits: This account includes costs associated with obtaining all site related permits for subsequent 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 an environmental impact statement or the safety analysis report.

Account 17 – Other Pre-Construction Costs: This account includes other costs that are incurred by Owner prior to start of construction and may include public awareness programs, site remediation work for plant licensing, etc.

Account 19 – Contingency on Pre-Construction Costs: This account includes an assessment of additional cost necessary to achieve the desired confidence level for the pre-construction costs not to be exceeded.

Account 20 – 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 installation, labor, and materials for concrete and metalwork for the building surrounding and supporting the nuclear island, including the reactor containment structure. Also includes the biological shielding around the reactor core, refueling canal (for PWRs, the steam generators would be located inside this structure), structural excavation and backfill, foundations, walls, slabs, siding, roof, architectural finishes, elevators, lighting, HVAC (general building service), fire protection, plumbing, and drainage.

Acct 213 **Turbine Generator Building:** (Secondary process facility) Includes installation, labor, and materials for concrete and structural metalwork 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.) Also includes structural excavation and backfill, foundations, walls, slabs, siding, roof, architectural finishes, elevators, lighting, HVAC, fire protection, plumbing, and drainage.

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 provides visitor control functions.

Acct 215* **Reactor Service (Auxiliary) Building** houses the fuel storage area, the spent-fuel pool, the control room, and most other balance of plant (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). includes facilities for receiving, storage, and services for handling reactor fuel assemblies.

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 (O&M) 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 such as a crane.

Acct 218Q* **Foundations for Outside Equipment and Tanks** such as Condensate storage tank or main transformer.

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 offsite 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, because the sub-account descriptions and costs depend heavily on the coolant used and whether the subsystems are factory-produced or constructed onsite. For today's LWRs, the entire nuclear steam supply system (NSSS) can be purchased as a unit from a reactor vendor. The reactor manufacturer 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 the 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) and feedwater piping from the 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, such as 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. This account includes all process equipment and systems associated with the plant output, the examples below are included for A – Electric Power Plant. For other plants, appropriate coding is required to separate the plant into logical and significant plant 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, the turbine bypass system, condenser-cleaning system, and piping from condenser to the feedwater heating system (Account 234). Condensate polishing is in Account 235.

Acct 234 **Feed Heating Systems:** Includes the feed heating system, feedwater heaters, feedwater system piping, the extraction steam system, and the feedwater heater vent and drain system. Piping to the 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 BOP I&C, including software, tubing, and fittings. 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 I&C costs in this account. The EMWG decided to retain I&C costs within the accounts that require I&C equipment, mainly Acct 227 and 236.) Accounts 21 through 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/BOP buildings.

Acct 241 **Switchgear:** Includes switchgear for the 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, auxiliary power and signal boards, 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, environmental monitoring equipment, raceway, cable, and connections. Excludes communication systems (Account 263) and building services such as lighting, HVAC, and fire protection (which are included in their respective building accounts).

Acct 245 **Electrical Raceway Systems:** Includes cable tray, exposed conduits, embedded conduits, underground conduit and duct systems, and the fittings, supports, covers, boxes, access holes, ducts, and accessories for the scheduled cable systems. Excludes raceways for protective systems (Account 244) and building services electrical systems (which are included in their respective building accounts).

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

Account 25 – Heat Rejection System: This account includes heat rejection equipment such as circulating water pumps, piping, valves, and cooling towers, which may be required even if the plant does not produce electricity. (This is Account 26 in the original EEDB [ORNL, 1988].)

Acct 251 **Structures:** Includes structures for the make-up water and intake, the circulating water-pump house, the make-up 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, and filters. Excludes condensers (Account 233) and natural draft towers (Account 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 equipment, instrument shop equipment, maintenance shop equipment, office equipment and furnishings, change room, and dining facility equipment.

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

Account 28 – Simulator(s): This account includes the development of new simulators for training operators.

Account 29 – Contingency on Direct Costs: This account includes the 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.3 Indirect Costs

In the original EEDB COA (ORNL, 1988), the "ninety-X" series is reserved for the indirect costs of reactor construction. For the IAEA account system (IAEA, 2000), it is the "thirty-X" and "forty-X" series. Nearly all these costs for the GIF COA are associated with costs incurred by the A/E firm, which are not considered "hands-on" construction. In the U.S., the percentage of funding dedicated to this area has increased for nuclear projects, largely as a result of increasing regulations and the need for more safety and quality assurance documentation. For these accounts, the COA dictionary is expressed at the two-digit (COA 30 and 40) levels.

<u>Account 30 – Capitalized Indirect Services Cost (CIC)</u>

***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 and rented equipment such as cranes, bulldozers, graders, and welders. 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 area maintenance, weather protection and repairs, snow clearing, and 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 through 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 are included with Account 38, PM/CM Services Onsite.

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

- 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 capitalized owner's cost (Account 40).

Account 34 – Demonstration Test Run: This account includes all services necessary to operate 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 conducted at the A/E home office and the equipment/reactor vendor's home office. Often pre-construction design is included here. These guidelines use the IAEA format for a 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. This account also includes site-related engineering and engineering effort (project engineering) required during construction of particular systems, which recur for all plants, and quality assurance costs related to design.

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 supplier, and A/E home offices.

Account 37 – Design Services Onsite: This account includes the same items as in Account 35, except that they are conducted at the plant site office or onsite temporary facilities instead of at an offsite office. This account also includes additional services such as 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 taking place at the plant site. It includes staff for quality assurance, office administration, procurement, contract administration, human resources, labor relations, project control, and medical and safety-related activities. Costs for craft supervisory personnel are included Account 32.

Account 39 – Contingency on Support Services: This account includes an assessment of additional cost necessary to achieve the desired confidence level for the support service costs not to be exceeded.

Account 40 – Capitalized Owner's Cost (COC)

Account 41 – Staff Recruitment and Training: This account includes costs to recruit and train plant operators before plant startup or commissioning activities (Account 33), or demonstration tests (Account 34).

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

Account 43 – Staff Salary-Related Costs: This account includes taxes, insurance, fringes, benefits, and any other salary-related costs.

Account 44 – Other Owner's Costs

Account 49 – Contingency on Owner's Costs: This account includes an assessment of additional costs necessary to achieve the desired confidence level for the capitalized owner's costs not to be exceeded.

Account 50 – Capitalized Supplementary Costs (CSC)

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

Account 52 – Spare Parts: This account includes spare parts furnished by system suppliers for the first year of commercial operation. It excludes spare parts required for plant commissioning, startup, or the demonstration run.

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

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

Account 55 – Initial Fuel Core Load: This account covers fuel purchased by the utility before commissioning, which is assumed to be part of the TCIC. In the U.S., the initial core is not usually included in the design/construction (overnight) cost sum to which interest during construction (IDC; see below) is added. Because the first core, however, will likely have to be financed along with the design/construction/startup costs, its cost is included in overnight costs as part of 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: This account includes the cost to decommission, decontaminate, and dismantle the plant at the end of commercial operation, if it is capitalized with the plant.

Account 59 – Contingency on Supplementary Costs: This account includes 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, because the contingency is already imbedded in the fuel cycle costs from the fuel cycle model**.**

Account 60 – Capitalized Financial Costs

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

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

Account 63 – Interest During Construction (IDC): This account is discussed in Chapter 7. 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: This account includes an assessment of additional cost necessary to achieve the desired confidence level for capitalized financial costs not to be exceeded, including schedule uncertainties.

F.4 Annualized Costs

The following accounts tabulate annual costs: (All costs are to be annualized as if incurred evenly each year.)

Account 70 - Annualized O&M Cost (AOC)

Account 71 – O&M Staff: This account includes salary costs of O&M staff

Account 72 – Management Staff: This account includes salary costs of operations management staff

Account 73 – Salary-Related Costs: This account includes taxes, insurance, fringes, benefits, and any other annual salary-related costs.

Account 74 – Operations Chemicals, and Lubricants

Account 75 – Spare Parts: Cost of any operational spare parts, excluding capital plant upgrades or major equipment that will be capitalized or amortized over some period or quantity of product.

Account 76 – Utilities, Supplies, and Consumables: Cost of water, gas, electricity, tools, machinery, maintenance equipment, office supplies and similar items purchased annually**.**

Account 77 – Capital Plant Upgrades: Upgrades to maintain or improve plant capacity, meet future regulatory requirements or plant life extensions.

Account 78 – Taxes and Insurance: Property taxes and insurance costs, excluding salary related.

Account 79 – Contingency on Annualized O&M Costs: This account includes an assessment of additional cost necessary to achieve the desired confidence level for the annualized O&M costs not to be exceeded.

Account 80 – Annualized Fuel Cost (ASC)

Account 81 – Refueling Operations: This account includes incremental costs associated with refueling operations.

Account 84 – Nuclear Fuel: This account includes annualized costs associated with the fuel cycle.

Account 86 – Fuel Reprocessing Charges: This account includes storage and reprocessing charges for spent fuel.

Account 87 – Special Nuclear Materials: Such as heavy water, sodium, lead, helium or other energy transfer mediums that are required on an annual basis, Includes costs associated with disposal or treatment if necessary.

Account 89 – Contingency on Annualized Fuel Costs: This account includes an assessment of additional cost necessary to achieve the desired confidence level for the annualized fuel costs not to be exceeded.

Account 90 – Annualized Financial Costs (AFC)

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

Account 92 – Fees: Cost of fees incurred for annual fees such as licensed reactor process, nuclear operating license fees, and similar.

Account 93 – Cost of Money: Value of money utilized for operating costs. May be financed externally or retained earnings.

Account 99 – Contingency on Annualized Financial Costs: This account includes an assessment of additional costs necessary to achieve the 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

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. End-use facilities for non-electric nuclear heat applications, such as thermal hydrogen, desalination, and actinide partitioning facilities, have also not yet been designed. In the course of preparing the Generation IV economic models, however, costs for new facilities designed to fulfill these needs must be estimated. Life cycle (including TCIC) cost estimates will be needed for the following facilities:

- 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
    - Mixed oxide (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 the Sodium-Cooled Fast Reactor/Integral fast reactor)
    - Waste packaging facilities
    - Onsite waste storage facilities
    - In-line reprocessing facilities located within the reactor area (e.g., for the Molten Salt Reactor)
- Non-electric end-use facilities associated with dedicated reactor(s):
    - Thermochemical hydrogen production plant
    - Electrolytic hydrogen production plant
    - Water desalination plant.

At the two-digit level, the basic COA for these facilities can be similar to those of electrical power plants. The only change would be in Account 23, which would now be called "Primary Product System Equipment" as opposed to "Turbine Generator 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 must be calculated. For fuel cycle facilities, unit costs, such as $/kg heavy metal processed, must be calculated. 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 costs must also be calculated to obtain the costs of end-use commodities, such as hydrogen or desalinated water.

Guidelines for these accounts are presented in Table F.1. Table F.2 shows the estimate report format.

Table F.1 Comparison of code of account 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 on Pre-Construction Costs		B19	Contingency on Pre-Construction Costs
A20	**Capitalized Direct Costs**		**B20**	**Capitalized Direct Costs**
A21	Structures and Improvements		B21	Structures and Improvements
A22	Reactor Equipment		B22	Not Applicable
A23	Turbine Generator Equipment		B23	Fuel Fabrication Process Equipment
A24	Electrical Equipment		B24	Electrical Equipment
A25	Heat Rejection System		B25	Heat Rejection System
A26	Miscellaneous Equipment		B26	Miscellaneous Equipment
A27	Special Materials		B27	Special Materials
A28	Simulator		B28	Simulator (if needed)
A29	Contingency on Capitalized Direct Cost		B29	Contingency on Capitalized Direct Cost
A30	**Capitalized Indirect Services Costs**		**B30**	**Capitalized Indirect Services Costs**
A31	Field Indirect Costs		B31	Field Indirect Costs
A32	Construction Supervision		B32	Construction Supervision
A33	Commissioning and Start-Up Costs		B33	Commissioning and Start-Up Costs
A34	Demonstration Test Run		B34	Demonstration Test 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 on Indirect Services		B39	Contingency on Indirect Services
A40	**Capitalized Owner's Cost**		**B40**	**Capitalized Owner's 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 Capitalized Costs		B46	Other Owner's Capitalized Costs
A49	Contingency on Owner's Costs		B49	Contingency on Owner's 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 on Pre-Construction Costs		D19	Contingency on Pre-Construction Costs
C20	**Capitalized Direct Costs**		**D20**	**Capitalized Direct Costs**
C21	Structures and Improvements		D21	Structures and Improvements
C22	Not Applicable		D22	Reactor Equipment
C23	Fuel Reprocessing Process Equipment		D23	Water Desalination Process Equipment
C24	Electrical Equipment		D24	Electrical Equipment
C25	Heat Rejection System		D25	Heat Rejection System
C26	Miscellaneous Equipment		D26	Miscellaneous Equipment
C27	Special Materials		D27	Special Materials
C28	Simulator		D28	Simulator (if needed)
C29	Contingency on Capitalized Direct Cost		D29	Contingency on Capitalized Direct Cost
C30	**Capitalized Indirect Services Costs**		**D30**	**Capitalized Indirect Services Costs**
C31	Field Indirect Costs		D31	Field Indirect Costs
C32	Construction Supervision		D32	Construction Supervision
C33	Commissioning and Start-Up Costs		D33	Commissioning and Start-Up Costs
C34	Demonstration Test Run		D34	Demonstration Test 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 on Indirect Services		D39	Contingency on Indirect Services
C40	**Capitalized Owner’s Cost**		**D40**	**Capitalized Owner’s 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 Capitalized Costs		D46	Other Owner’s Capitalized Costs
C49	Contingency on Owner’s Costs		D49	Contingency on Owner’s 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 on Pre-Construction Costs		F19	Contingency on Pre-Construction Costs
E20	**Capitalized Direct Costs**		**F20**	**Capitalized Direct Costs**
E21	Structures and Improvements		F21	Structures and Improvements
E22	Reactor Equipment		F22	Reactor Equipment
E23	Hydrogen Generation Process Equipment		F23	“Other Process” Process Equipment
E24	Electrical Equipment		F24	Electrical Equipment
E25	Heat Rejection System		F25	Heat Rejection System
E26	Miscellaneous Equipment		F26	Miscellaneous Equipment
E27	Special Materials		F27	Special Materials
E28	Simulator		F28	Simulator (if needed)
E29	Contingency on Capitalized Direct Cost		F29	Contingency on Capitalized Direct Cost
E30	**Capitalized Indirect Services Costs**		**F30**	**Capitalized Indirect Services Costs**
E31	Field Indirect Costs		F31	Field Indirect Costs
E32	Construction Supervision		F32	Construction Supervision
E33	Commissioning and Start-Up Costs		F33	Commissioning and Start-Up Costs
E34	Demonstration Test Run		D34	Demonstration Test 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 on Indirect Services		F39	Contingency on Indirect Services
E40	**Capitalized Owner’s Cost**		**F40**	**Capitalized Owner’s 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 Capitalized Costs		F46	Other Owner’s Capitalized Costs
E49	Contingency on Owner’s Costs		F49	Contingency on Owner’s Costs

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APPENDIX G. DATA FOR COST ESTIMATING

The following sections contain data tables defining the estimate pricing basis, providing reference plant data, and illustrating an example of the use of reference plant data. Section G.4 describes the estimate validation practices.

G.1 Definition of Estimate Pricing Basis

Table G.1.1 Composite labor crews and costs (U.S.), as of January 1, 2007

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	
Unit	$/h	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.	%	Contr.
Boiler maker	48.64							15	7.3						
Carpenter	39.98	40	15.99	5	2									2	0.8
Electrician	48.23											70	33.76	96	46.3
Iron Worker	45.28	20	9.06	75	33.96			10	4.53						
Laborer	31.34	30	9.4	5	1.57	60	18.8							1	0.31
Millwright	43.01							25	10.75						
Operating Engineer	43.24	5	2.16	15	6.49	35	15.13	12	5.19	15	6.49	2	0.86	1	0.43
Pipe fitter	48.66							35	17.03	80	38.93	28	13.62		
Teamster	34.14					5	1.71	3	1.02	5	1.71				
Others	38.34	5	1.92												
		100	38.53	100	44.02	100	35.64	100	45.82	100	47.13	100	48.24	100	47.84

Table G.1.2 Bulk commodity pricing (U.S.), as of Jan. 1, 2007

Commodity	Unit	Nuclear $	Non-nuclear $
Structural Commodities			
Formwork	SM	31.23	29.14
Decking	SM	132.62	79.57
Reinforcing steel	MT	1,278.50	821.92
Embedded metal	KG	13.06	7.87
Concrete	CM	208.93	139.20
Structural steel	MT	4,446.70	2,008.07
Miscellaneous steel	MT	10,269.48	4,658.13
Piping Commodities			
50 mm. and under screwed pipe	LM	180.83	146.05
50 mm. and under CS welded pipe	LM	250.38	180.83
50 mm. and under CM welded pipe	LM	369.04	278.63
50 mm. and under SS welded pipe	LM	369.04	278.63
100 mm. CS sch 40 (0.237 in.) spooled pipe	LM	514.06	221.15
100 mm. CM sch 40 (0.237 in.) spooled pipe	LM	1,295.33	738.08
100 mm. SS sch 40 (0.237 in.) spooled pipe	LM	1,549.97	926.29
300 mm. CS sch 80 (0.688 in.) spooled pipe	LM	2,344.74	2,108.95
300 mm. CM sch 80 (0.688 in.) spooled pipe	LM	5,980.29	5,539.29
300 mm. SS sch 80 (0.688 in.) spooled pipe	LM	9,305.34	8,936.30
500 mm. CS sch 120 (1.50 in.) spooled pipe	LM	6,448.41	6,096.92
Electrical Commodities			
50 mm. dia. rigid steel exposed conduit	LM	43.84	29.06
100 mm. dia. non-metallic duct bank conduit	LM	21.09	16.84
600 x 25 mm. aluminum cable tray	LM	94.50	62.87
600 volt power and control cable (Avg. 5 C, #12)	LM	12.51	9.88
600 volt instrumentation cable (Avg. 2 Pr., Shld, #18)	LM	6.45	5.14
5-15 kV power cable (Avg. 3 C, #250)	LM	32.79	26.34
600 volt connections	EA	3.60	1.80
5-15 kV connections	EA	168.43	115.71

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

Table G.1.3 Bulk commodity unit hour installation rates (U.S.) (5 x 8 = 40 hour working week, replica plants)

Commodity	Unit	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.1.4 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, 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 onsite batch plant. Values include heat control or ice addition, patch and sack, curing mixes, hardeners, and 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. 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 and field-fabricated or onsite pre-fabricated material. 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 and associated 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.1.5 - Escalation adjustment factors

	GIF Code of Accounts												
Initial Year	21 Civil Struct.	22 Reactor Plant	23 T/G Plant	24 Electric Plant	25 Heat Reject	26 Misc. Equipment	27 Special Nuclear. Material.	28 Simulator	29 Contingency	20 Plant Materials Total	20-30 Craft Labor	32 Constr. N/M Labor	20-30 Nuclear Plant TOTAL
1992	1.651	1.489	1.348	1.713	1.348	1.348	1.489	1.713	1.578	1.509	1.661	1.609	1.578
1993	1.569	1.467	1.321	1.729	1.321	1.321	1.467	1.729	1.540	1.484	1.608	1.555	1.540
1994	1.492	1.425	1.305	1.647	1.305	1.305	1.425	1.647	1.501	1.444	1.572	1.512	1.501
1995	1.454	1.370	1.259	1.518	1.259	1.259	1.370	1.518	1.449	1.381	1.530	1.477	1.449
1996	1.409	1.358	1.231	1.574	1.231	1.231	1.358	1.574	1.432	1.365	1.519	1.426	1.432
1997	1.379	1.326	1.211	1.559	1.211	1.211	1.326	1.559	1.399	1.337	1.482	1.386	1.399
1998	1.383	1.301	1.192	1.613	1.192	1.192	1.301	1.613	1.365	1.320	1.426	1.339	1.365
1999	1.390	1.318	1.178	1.749	1.178	1.178	1.318	1.749	1.350	1.329	1.386	1.294	1.350
2000	1.394	1.283	1.164	1.647	1.164	1.164	1.283	1.647	1.309	1.301	1.330	1.246	1.309
2001	1.403	1.264	1.134	1.739	1.134	1.134	1.264	1.739	1.279	1.286	1.286	1.198	1.279
2002	1.433	1.220	1.130	1.742	1.130	1.130	1.220	1.742	1.248	1.265	1.243	1.166	1.248
2003	1.428	1.250	1.127	1.700	1.127	1.127	1.250	1.700	1.216	1.274	1.167	1.143	1.216
2004	1.145	1.095	1.105	1.354	1.105	1.105	1.095	1.354	1.132	1.125	1.143	1.109	1.132
2005	1.063	1.065	1.051	1.275	1.051	1.051	1.065	1.275	1.072	1.077	1.074	1.034	1.072
2006	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Notes:
a. Cost escalation factors from Initial Year to January 1, 2007
b. December 31 of year shown
c. Source from BLS-WPI indexes referenced in Table G.1.6

Table G.1.6 Escalation Index Source Data

GIF	COA Description		Line #	COMMODITY DESCRIPTION			
COA		Commodity		% Line #	LINE DESCRIPTION	SOURCE	INDEX #
21	Civil, Structural	10-20	507	BULK CIVIL MATL COST			
			126	10%	SOFTWOOD LUMBER	BLS-WPI	811
			139	20%	STRUCTURAL PLATE	BLS-WPI	101704
			146	20%	REINFORCING BAR	BLS-WPI	10740794
			167	20%	STRUCT/ARCH MTL	BLS-WPI	1074
			214	30%	CONCRETE, READY MIXED	BLS-WPI	3273201
22	Reactor	30	503	NSSS AND TG MATL COST			
			135	39%	STEEL MILL PRODUCTS	BLS-WPI	331111
			377	61%	ELECTRICAL EQUIPMENT	BLS-EE	EEU31360006(n)
23	T/G	41-42	504	OTHER EQUIPMENT MATL COST			
			176	50%	GENL PURP MACHY & EQUIP	BLS-WPI	114
			198	50%	SWITCHGEAR	BLS-WPI	335313A
24	Electical	60-70-80	505	BULK ELECTRICAL MATL COST			
			135	50%	STEEL MILL PRODUCTS	BLS-WPI	331111
			158	50%	NONFERROUS WIRE & CABLE	BLS-WPI	1026
25	Heat Reject	44	504	OTHER EQUIPMENT MATL COST			
			176	50%	GENL PURP MACHY & EQUIP	BLS-WPI	114
			198	50%	SWITCHGEAR	BLS-WPI	335313A
26	Misc Eq	43, 45-49	504	OTHER EQUIPMENT MATL COST			
			176	50%	GENL PURP MACHY & EQUIP	BLS-WPI	114
			198	50%	SWITCHGEAR	BLS-WPI	335313A
20	Total Material		513	MATERIAL COST - NUCLEAR			
			503	45%	NSSS AND TG MATL COST		
			504	28%	OTHER EQUIPMENT MATL COST		
			508	28%	AVERAGE BULK MATL COST		
				505	33% BULK ELECTRICAL MATL COST		
				506	33% BULK PIPING MATL COST		
					168 60% FABD STEEL PIPE & FTGS	BLS-WPI	332996
					188 40% C.S. VALVES	BLS-WPI	332919P
				507	33% BULK CIVIL MATL COST		

Table G.1.6 Escalation Index Source Data (cont.)

	COA Description		Line #	COMMODITY DESCRIPTION			
COA		Commodity		% Line #	LINE DESCRIPTION	SOURCE	INDEX #
20-30	Craft Labor		510	MANUAL LABOR - NUCLEAR			
			351	17%	LABORER	ENR	
			352	20%	CARPENTER	ENR	
			353	11%	IRONWORKER Reinforcing)	ENR	
			354	16%	ELECTRICIAN	ENR	
			355	28%	PIPEFITTER	ENR	
			356	6%	OPERATOR (crane)	ENR	
			357	2%	TRUCK DRIVER	ENR	
32	Construction Non Manual		511	CONSTRUCTION NONMANUAL LABOR COST			
			320A	100%	BLS PROF/TECH. PRIV. IND.	BLS-ECI	ECU21122I
20-30	Total Plant		515	TOTAL PLANT - NUCLEAR			
			510	35%	MANUAL LABOR - NUCLEAR		
			511	7%	CONSTRUCTION NONMANUAL LABOR COST		
			513	58%	MATERIAL COST - NUCLEAR		

ABBREVIATIONS

BLS-EE - BUREAU OF LABOR STATISTICS - EMPLOYMENT AND EARNINGS
AVERAGE HOURLY EARNINGS OF PRODUCTION WORKERS NOT SEASONALLY ADJUSTED

BLS-ECI - BUREAU OF LABOR STATISTICS - EMPLOYMENT COST INDEX: USE THE
"NOT SEASONALLY ADJUSTED" TABLE. "WAGES & SALARIES -
PRIVATE INDUSTRY WORKERS - CATEGORY: PROFESSIONAL, SPECIALTY,
& TECHNICAL OCCUPATIONS."

BLS-PPI & WPI BUREAU OF LABOR STATISTICS - PRODUCER PRICE INDEXES
Available on the web at www.bls.gov/data/home.htm scroll down to "Prices & Living Conditions".
- PPI represents Producer Price Index - Industry data
- WPI represents Producer Price Index - Commodity data (Wholesale Price index)

ENR - ENGINEERING NEWS RECORD MAGAZINE

Table G.1.7 Currency exchange rates

Currency	US $1.000 =		= USD ($)
Australian Dollar	1.268390	AUD	0.7884
British Pound	0.510569	GBP	1.9586
Canadian Dollar	1.166520	CAD	0.8573
Chinese Yuan	7.804100	CNY	0.1281
European Euro	0.757748	EUR	1.3197
Hong Kong Dollar	7.777100	HKD	0.1286
Japan Yen	119.020000	JPY	0.0084
New Zealand Dollar	1.419240	NZD	0.7046
Norwegian Kroner	6.228700	NOK	0.1605
Singapore Dollar	1.533800	SGD	0.6520
South African Rand	7.037500	ZAR	0.1421
South Korean Won	930.000000	KRW	0.0011
Swedish Krona	6.834200	SEK	0.1463
Swiss Franc	1.219500	CHF	0.8200
Taiwan Dollar	32.590000	TWD	0.0307
United States Dollar	1.000000	USD	1.0000
Venezuelan Bolivar	2,144.000000	VEB	0.0005

G.2 Reference Plant Data

The following data depict U.S. nuclear plant construction experience for light-water reactors (LWRs). Much of the tabulated relationships may be influenced by U.S.-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 Generation IV needs.

Table G.2.1 1970s LWR U.S. 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 1970s LWR U.S. 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 1970s LWR U.S. 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 1970s LWR U.S. 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 1970s LWR U.S. experience data, two units and common 2 x 1086-MWe BWR, fuel load 7/82 and 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 1970s LWR U.S. 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 1970s LWR U.S. 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 bases and cost development techniques that may be used to estimate 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
Nuclear island 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	B. Global	Parameter 2	Plant B	Plant B	Plant B
Reactor protection systems	Plant B	Top-down	B. Global	Parameter 3	Plant B	Plant B	Plant B
Fuel handling system	Plant C	Top-down	C. Global	Parameter 4	Plant C	Plant C	Plant C
Other reactor systems	Plant D	Top-down	D. Global	Parameter 5	Plant D	Plant D	Plant D
Radwaste	Plant E	Top-down	E. Global	Parameter 6	Plant E	Plant E	Plant E
T/G systems	Plant F	Top-down	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

The following is an example of a top-down cost estimate for a nuclear steam supply system, using 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 factors for each detailed account.

Table G.3.3 Sample reference plant, cost factor development

		REFERENCE PLANT TO SUBJECT PLANT COST FACTORS								
								COMPONENT COST FACTOR		
COA			Ref Plant	Subject	Parameter	Cost Factor	Cost	FACTORY	SITE	SITE
Number	Description	Parameter	Value	Value	Ratio	Exponent	Factor	EQUIP	HOUR	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					
		FACTORY	SITE	SITE	SITE	NI	FACTORY	SITE	SITE	SITE	BOP	TOTAL
COA	Description	EQUIP	HOUR	LABOR	MATL	TOTAL	EQUIP	HOUR	LABOR	MATL	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 each modularized account. 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		

COA		%	SUBJECT PLANT CALCULATED (MODULARIZED)										
			NUCLEAR ISLAND					BALANCE OF PLANT					
Number	Description	Factory Module	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		% 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 the cost of money.

G.4 Estimate Validation

To validate estimates, estimating teams should compare major estimate and plant parameters to reference plant data and explain them with supporting data. Some or all of the following parameter checks could be used:

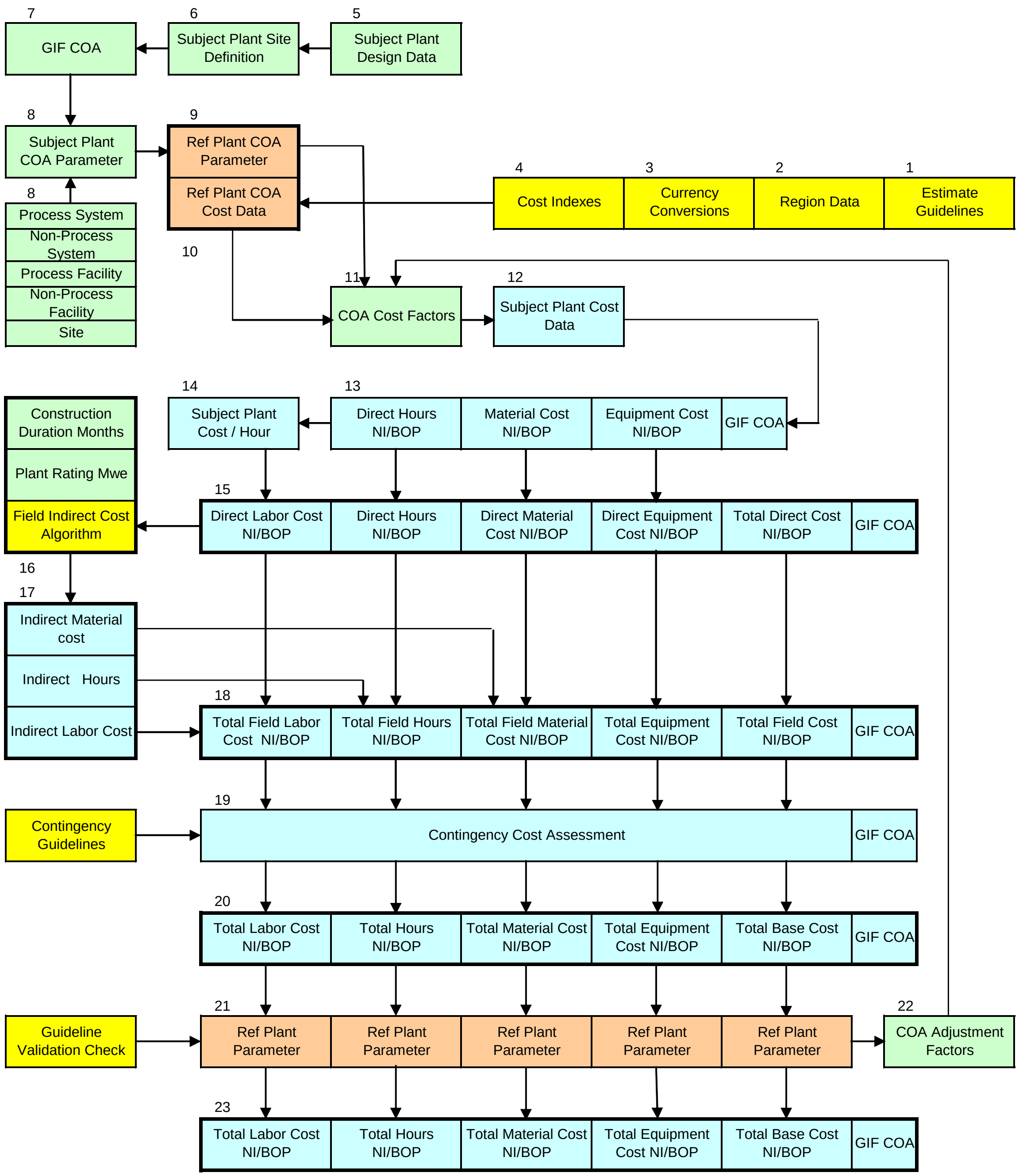
1. Parameters per kWe – Process equipment cost, material cost, direct hours, direct cost, Code of Account (COA) summary, and category costs. See Tables G.2.1 through G.2.6.
2. Bulk ratios to process equipment – Materials per $1,000 of process equipment cost, installation hours per $1,000 of process equipment 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, or field indirect COA total hour percentage of total direct hours. See Tables G.2.1 through G.2.6 for 1970s U.S. 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 1970s U.S. 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 parameters and comparisons with reference plant data. See Table G.2.7 for 1970s U.S. 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 1970s U.S. nuclear plant experience data.

APPENDIX H. TOP-DOWN ESTIMATING PROCESS

Chapter 5 provided guidance for top-down cost estimating using the Generation IV International Forum (GIF) Code of Accounts (COA). This appendix presents a simplified top-down estimating process which utilizes reference plant detail estimate data as depicted in Figure H.1. The discrete steps depicted in the diagram correspond to the item numbers following the Figure H.1.

Figure H.1 Simplified top-down estimating process



Yellow = Guideline data, Orange = Reference plant data, Green = Subject plant data, Blue = Subject plant calculations

The first four items are general data sources of a more regional nature rather than specific to system design. The data are required to convert and adjust reference plant cost data before developing subject plant cost estimates.

1. Estimate Guidelines – Review these guidelines for requirements in format, content, and methodology.
2. Region Data – Determine regional cost data, productivity factors, pricing levels, cost indexes, currency conversion factors, and other regional information.
3. Currency Conversions – Establish currency conversion factors for all regions.
4. Cost Indexes – Establish cost indexes for all regions to adjust reference plant costs to nominal cost date.
5. Subject Plant Design Data – Review the subject plant design and establish all major parameters to estimate cost relationships with reference plants (e.g., plant rating MWe, building areas and volumes, system data, and heat balance).
6. Subject Plant Site Definition – Review the subject plant site-specific scope and establish parameters to define the subject plant site-specific costs.
7. GIF COA – Compare 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 COA Parameter – Segregate subject plant scope into 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, 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; or another suitable parameter.
9. Reference Plant COA Parameter – Select a reference plant that contains the required cost element with corresponding plant parameter data.
10. Reference Plant COA Cost Data – Adjust the reference plant cost data for the required pricing levels, productivity levels, and cost component separation, including the 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 appropriate to the cost element, calculate the cost adjustment factor.
12. Subject Plant Cost Data - 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, staffing 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 at the two- or three-digit level of the GIF COA, including direct hours, material cost, and equipment costs of the nuclear island and BOP.

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 a composite labor cost per hour including all benefits, 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 – Extend the subject plant direct labor hours, derived from the reference plant cost data, by the appropriate cost per hour to estimate the labor cost component and add it to the equipment cost and material costs to calculate the subject plant total direct cost.
16. Field Indirect Cost Algorithm – Calculate the field indirect costs with algorithms that relate the size of plant and duration of the construction period relative to the direct craft labor cost (see Section 5.4).
17. Field Indirect Costs – Field indirect costs consist of three components that are related to:
    - one time charges, such as temporary facilities purchased and erected at start of construction
    - schedule duration-related costs, such as equipment rentals and site cleanup
    - direct construction-related costs, such as tools and consumables.

    Use suitable algorithms to calculate field indirect costs and hours. The resultant craft hours together with the planned construction schedules provide the basis to develop staff levels and curves.
18. Subject Plant calculation – Summarize direct cost and field indirect costs to produce total field cost, which provides the baseline cost data to calculate design and project management/construction management services.
19. Contingency Cost Assessment – Assess contingency for the subject plant estimated costs to derive the appropriate contingency costs for each summary account code level (see Appendix A).
20. Total Subject Plant Costs – The subject plant costs are summarized to appropriate levels of the GIF COA.
21. Validation – Validate the information to compare the subject plant cost estimate relative to cost parameters derived from reference plant cost data. Parameters include 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$ 1,000) of equipment cost, among others (see Appendix G).
22. COA Adjustment Factors – Recycle the results of the validation process to adjust the cost factors in Step 11 until the results are validated relative to established parameters for reference plant cost data.
23. Base Cost Calculation – Summarize the data to result in base cost before calculation of other capitalized costs and total overnight cost.

A summary of the two-digit COA provides input to other cost models to calculate the levelized unit of energy cost.