ELECTRIC POWER RESEARCH INSTITUTE

Quantifying the Value of Hydropower in the Electric Grid

Plant Cost Elements

2011 TECHNICAL REPORT

Quantifying the Value of Hydropower in the Electric Grid

Plant Cost Elements

EPRI Project Manager
T. Key

ELECTRIC POWER RESEARCH INSTITUTE

3420 Hillview Avenue
Palo Alto, CA 94304-1338
USA

PO Box 10412
Palo Alto, CA 94303-0813
USA

800.313.3774
650.855.2121

askepri@epri.com

www.epri.com

1023140

Final Report, November 2011

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THE FOLLOWING ORGANIZATION(S), UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

HDR Engineering, Inc.

NOTE

Acknowledgments

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

HDR Engineering, Inc.
400 S. Tryon St, Suite 2401
Charlotte, North Carolina 28285

Principal Investigators
S. Brown
J. Gibson
R. Grady
R. Miller
A. Roth
J. Sigmon
D. Summers

This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements. EPRI, Palo Alto, CA: 2011. 1023140.

Abstract

In an effort to quantify the full value of hydropower assets in a future electric grid, a team of researchers has looked at energy futures, regional markets, plant technologies, and operations. This report addresses the cost-side of the cost-benefit equation to be used when considering hydropower facility investments. It identifies construction and modification elements and estimates associated with costs for pumped storage, conventional hydro, and non-powered facilities. Cost data from original plant construction or modifications are carefully escalated for application to today's hydropower investment options, including new Greenfield sites as well as upgrades and improvements at existing facilities. In addition, cost data from more recent projects are captured and compared to escalated costs from prior construction experience.

The work reported in this Technical Update is part of a larger research effort to improve valuation and resource planning methods for hydropower assets supporting the electric transmission system. The focus of this effort has been to look ahead to a future electricity grid and generation mix that is changing by addition of more renewable and variable resources. As these changes occur in the grid, conventional hydropower and pumped storage assets are expected to increase in value by providing flexibility and ancillary services. However, methods to quantify this value are not readily available or easily applied. Therefore, the broad goal of this research is to employ several industry analyses and modeling tools and to better quantify the cost and benefits of hydropower in the future electric grid.

Keywords

Pumped storage cost
Low-head hydro cost
Greenfield hydropower
Construction cost escalation

Executive Summary

Concerns about energy security and climate change are driving policies, regulations, and market changes to encourage “new” renewables, such as wind and solar, and traditional renewables, primarily hydropower. In the past, electric capacity expansion models and resource plans have often take ancillary services for granted and have tended to discount the potential value hydropower. Expected future limits on CO2 emissions and the addition of variable renewables, primarily wind, can shift economic breaks-points in favor of hydropower options, including the addition of pumped storage. Wind power, in particular, introduces system balancing requirements that could make many hydropower assets more valuable. However, the actual costs and benefits from hydropower projects are not fully recognized under existing policies and market structures.

DOE-EE0002666 Quantifying the Value of Hydropower in the Electric Grid Project

Completing a cost and benefit analysis that includes all the important assumptions and variables to accurately predict the future value of hydropower plants to the transmission grid is a difficult task. In order to overcome this difficultly, EPRI has assembled a unique and diverse team. The team is made up of organizations with experience in grid modeling, hydropower costs, and markets, as well as experts in hydropower operations. The two-year project scope includes the following specific tasks:

Task 1 - Case Studies on Plant Operations and Utilization
Task 2 - Modeling Approach and Base Case Scenario
Task 3 - Role of Hydropower in Existing Markets and Opportunities in Future Markets
Task 4 - Systemic Plant Operating Constraints
Task 5 - Plant Cost Elements
Task 6 - Modeling Results for Future Scenarios
Task 7 - Effects of Alternative Policy Scenarios on Value of Hydropower
Task 8 - Planning and Operating Strategies
Task 9 - Final Report

Utilities with existing or planned hydropower will gain understanding of the costs and benefits for providing ancillary services under different future scenarios including high levels of renewable integration. Results will also be useful in formulating policies and regulations, for developing fair markets, and for investing in energy and transmission infrastructure to ensure energy security and to address climate change concerns. Uses include quantifying benefits provided by conventional and pumped storage hydro projects to the transmission grid, validating a power and market systems model, analyzing scenarios, and examining the implications of alternative market structures.

Task 5 of this project involves developing a database of current and projected cost elements for pumped storage and conventional hydropower development options. This task will provide input for future modeling efforts, as well as a reference database of current and projected costs for constructing new projects, and increasing capacity and efficiency at conventional hydropower, pumped storage, and non-powered facilities.

Plant Cost Elements (Task 5)

This report presents the results of HDR's study, which expands on previous DOE and EPRI research efforts by capturing actual, available costs for various project elements and comparing these to the projected costs developed in these previous efforts. Cost data are escalated and applied to various hydropower applications including greenfield projects and upgrades/improvements at existing facilities.

Cost elements include front end studies, analysis and engineering, capital and construction costs, permitting costs, and indirect/life cycle operation and maintenance costs. Updating and escalating techniques include procedures developed by the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation, recent studies and vendor/contractor quotes, published labor and material indices, and recently completed projects and operations costs, as available.

Cost data resulting from this analysis are compared to data available from recent HDR studies and other studies where recent construction and operation costs are available. This assures the cost data is comparable for hydro applications. Results of this task will provide input for future modeling efforts, as well as a reference database of current and projected costs for adding and increasing efficiency and capacity at conventional hydropower, pumped storage, and non-powered facilities.

Table of Contents

List of Figures

List of Tables

Section 1: Introduction

In September 2009, the U.S. Department of Energy (DOE) selected the Electric Power Research Institute (EPRI) Project Team, consisting of EPRI, HDR Engineering, Inc. (HDR), Hydro Performance Processes Inc. (HPPi), LCG Consulting, Oak Ridge National Laboratory (ORNL), and Sandia National Laboratory, to conduct a two-year project to develop “new methods to quantify and maximize the benefits that conventional hydropower and pumped storage hydropower provide to transmision grids.” The project is being performed under Funding Announcement Number DE-FOA-0000069 Advanced Water Power Topic Area 4: Hydropower Grid Services.

The primary goal of the DOE project is to benchmark the current role of hydropower and to provide a better understanding of the future role of this renewable energy resource, including pumped storage, for providing grid services. The project will develop an approach that quantifies the full potential value of hydropower resources to the U.S. electric grid.

Task 5 of this project involves developing a database of current and projected cost elements for alternative pumped storage and conventional hydropower development options. This task, completed by HDR with support from the EPRI Team, will provide input for future modeling efforts, as well as a reference database of current and projected costs for constructing new projects, and increasing efficiency and capacity at conventional hydropower, pumped storage, and non-powered facilities, including incremental expansions at existing facilities, new pumped storage hydropower at greenfield sites, and control system and optimization improvements.

This report presents the results of HDR’s study, which expands on DOE and EPRI research efforts conducted during the 1990s and early 2000s, by capturing actual, available costs for various project elements and comparing these to the projected costs developed in these previous efforts. Cost data are obtained for the logical grouping of project elements, escalated, and applied to various hydropower applications including greenfield projects and upgrades/improvements at existing facilities.

Updating and escalating techniques include procedures developed by the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation, recent studies and hydropower equipment vendor/contractor opinions, published labor and material indices, and recently completed projects and operations costs, as available. This assures the cost data is comparable for hydropower applications.

Section 2: Scope of Work

The scope of this study is intended to support the larger DOE Hydropower Grid Services Project by providing input for future modeling efforts, as well as a reference database of current and projected costs for adding and increasing efficiency and capacity at conventional hydropower, pumped storage, and non-powered facilities. This study consists of the following tasks:

§ Task 1: Identify the range of options for increasing output and storage efficiency at pumped storage and conventional hydropower facilities considering:

  - Increased capacity at existing pumped storage facilities, efficiency improvements, adding additional water conveyance and units, changes in operational modes, new technologies including variable speed generators;
  - Increased capacity at existing conventional hydropower facilities, efficiency improvements, adding additional water conveyance and units, changes in operational modes, new technologies including variable speed generators (for pumped storage applications), and advanced pump-back retrofits; and
  - Added capacity to existing non-powered dams, water supply projects, and irrigation projects.

§ Task 2: Update and escalate project costs from prior experience considering:

  - Screening-level cost opinions for greenfield pumped storage hydroelectric development;
  - Screening-level cost opinions for greenfield conventional hydroelectric development;
  - Guidance from the American Association of Cost Engineering (AACE) Class 5 cost classification system, which is based on the lowest level of project definition; and
  - The role of permitting on total project costs and uncertainty, with emphasis on greenfield pumped storage hydroelectric development.

Cost results from this analysis are compared to data available from more recent HDR studies and data obtained from others, including domestic and international utility and agency partners/manufacturers, where more recent hydropower construction costs may be available.

Section 3: Options for Increasing Output and Efficiencies at Pumped Storage and Conventional Hydropower Facilities

Each hydropower rehabilitation or upgrade/modernization program or project has its own unique objectives, which can include:

§ Extending service life

§ Halting or decelerating deterioration

§ Increasing generating capacity

§ Improving efficiency

§ Reducing risk of catastrophic failure

§ Reducing forced outages or unscheduled down time

§ Improving ability to control equipment via remote control or automation

§ Improving ability to deliver "ancillary services"

§ Improving ability to meet river flow or reservoir level requirements

§ Matching unit performance characteristics to load or water availability, including removing "bottlenecks" in cascade hydro systems

§ Improving plant/personnel safety

§ Reducing potential for environmental degradation

§ Enhancing water quality

§ Reducing fish mortality

§ Reducing operations or maintenance costs

§ Reducing frequency of overhauls or scheduled outages

- Reducing undesirable running characteristics, such as vibration
- Avoiding obsolescence problems such as lack of manufacturer support or unavailability of replacement parts
- Meeting legal/licensing requirements

This section discusses various methods of increasing output and efficiency at existing pumped storage and conventional hydropower facilities; and adding capacity to non-powered dams, water supply projects, and irrigation projects. Information presented in this section was derived from Volumes 2 and 3 of EPRI's Hydro Life Extension Modernization Guides (EPRI 2000a, 2001a). Refer to these volumes for further details regarding the scope of items discussed.

As many of the methods utilized to increase capacity and efficiency at existing conventional and pumped storage hydro facilities are the same, these will be addressed together, with indication of whether they apply to only one or the other.

It is important to note that not all conceivable methods to upgrade units are included, as the list would be unmanageable and not necessarily applicable to all installations. Therefore, the following items comprise methods that have been implemented in most upgrade projects seen to date and create a logical starting point for the consideration of unit modernization.

3.1 Capacity Increases

Because plant components often have different ratings or design margins, the capability of each component in the plant must be considered before uprating the component and plant capacities. Therefore, alternative uprating plans differ in the number of components for which uprating is required. The higher the uprating capacity, the more components affected, with proportionally higher costs.

To eliminate bottlenecks or limitations on a plant's output, one must consider the existing and uprating potential of the following major components that determine plant capacity:

- Intake and trashrack
- Headrace canal or tunnel
- Penstock(s)
- Turbine(s)
- Tailrace canal or tunnel
- Generator(s)
- Transformer(s)
- Transmission lines

The cost of other affected components and auxiliaries such as the governor, valves, and switchgear would be added to the cost of the appropriate alternative. These costs are usually less significant than those for the major components.

Because of differences in design criteria among components, the uprating potential of a plant or a specific component typically occurs in steps that are not linear. Each specific component change results in an increase in plant potential that is independent of other components. Some examples of step increases are a new runner that would increase the turbine capacity or a generator rewind that would increase the generator capacity. However, replacing only the turbine runner or rewinding the generator may not provide the desired upgrade. Limitations of all components in the power train need to be considered. In addition, space constraints can have an impact.

In developing the initial uprating plans, the technical uprating options for each major component should be determined independently, neglecting cost considerations.

The types of units addressed include Francis (both conventional and reversible pump-turbines), Fixed-Blade Propeller, Kaplan, and Pelton. Other types of machines (e.g., Turgo and Cross-flow) are acknowledged, but are not included in the scope of this study.

Methods to obtain capacity increases are limited to the major power train components in this section.

3.1.1 Runner Replacement

The runner is usually the most significant turbine or pump-turbine component selected for modernization consideration, based on both cost of implementation and upgrade potential.

Modern turbines have significant advantages over those from previous decades. Advances in analytical, computer, and model testing techniques, as well as in materials and manufacturing methods, have allowed improvements in all aspects of performance. Because runner design methodology at the time of original installation did not have the benefits of modern techniques and computerization, the opportunity for modernization of older units is very realistic.

Most if not all pump-turbine runner replacement projects have included testing of a fully homologous scale model in the scope. It is highly recommended that such a test be included in the scope of any pump-turbine runner replacement.

For the costs of increasing output, it has been assumed that the runner upgrade will not infringe on the mechanical limitations of the remaining turbine and/or generator components. It should be noted, however, that increased output can affect other components of the power train and assessment of those impacts needs to be included with any modernization analysis.

Typically, capacity increases achieved through upgrading the turbine with a new runner design will result in increased flows through the unit. Increased flows (and output) can affect licensing requirements (refer to Section 4.7.8).

Incremental Scope Considerations

Discharge Ring Extension (Francis Turbines and Pump-Turbines) – To achieve some desired increases in capacity, several manufacturers employ a design methodology that results in an axial lengthening of the runner band, thereby necessitating a modification to the turbine discharge ring. In addition to the manufacture of the ring extension piece, such a modification involves minor civil work (e.g., concrete removal and grouting) associated with the installation of the ring.

Discharge Ring Diameter Increase (Propeller/Kaplan Turbines) – Increases in output can be achieved by increasing the runner diameter of propeller/Kaplan turbines, which involves replacement of the discharge ring to accommodate the larger diameter runner. This modification involves extensive civil works to remove the old ring and install the new ring.

Should a runner diameter increase be considered, modifications to, as a minimum, the draft tube cone will be required to transition from the larger discharge ring to the existing draft tube.

Increased Wicket Gate Opening (Reaction Turbines) – Depending on the increase in flow associated with the capacity upgrade, it may be necessary to increase the maximum wicket gate opening to deliver the required flow rate to the runner. This modification involves increasing the servomotor stroke, which typically requires modification of the servomotors and, sometimes, the wicket gate operating linkage.

Increase Nozzle Opening (Impulse Turbines) – Output of a Pelton turbine can be increased with enlarged needle seats, either as part of a runner upgrade or as a stand-alone effort. The needle servomotors may be affected because of the change in operating conditions. A large increase in nozzle diameter will often require a redesign of the nozzle assembly and the needle shaft.

3.1.2 Stator Rewind

Generators in older plants were conservatively designed and constructed and, generally, have potential for improved performance. The greatest potential exists in the ability to increase generator capacity by modifying the generator design and by upgrading major components. This is accomplished with more efficient winding designs and improved insulation materials capable of operating at higher temperatures.

If the winding is more than 30 years old, uprating will generally be possible with a new winding using modern insulation systems. The newer insulations are generally thinner, allowing more copper cross section in the slot, which permits the uprating at acceptable temperature levels.

The following should be noted when considering a stator rewind:

- The condition of the stator core,
- The capability of the field winding, and
- Modification to the stator frame and bearing supports, which may be necessary if capacity is increased.

Incremental Scope Considerations

Stator Core Restack – Stator core replacement should be considered if the existing stator core is deteriorated or damaged, or if a greater increase in output is desired than can be achieved by rewinding using the existing core. Stator core replacement is often performed in conjunction with replacement of the windings.

Field Pole Winding Reinsulation – When considering an uprate, all field winding and coil components should be restored to as-new condition. If necessary for uprating, the conductor copper cross section may also be increased.

3.1.3 Project Expansion – New Water Conveyance and New Units

Many pumped storage projects developed within the U.S. from around 1960 through 1991 were developed with weekly or longer cycles to load during peak periods of the week and utilize large baseload generating facilities for pump-back over the weekend with excess power. With the influx of intermittent renewable generating sources, there is a growing trend within the pumped storage industry to increase capacity and thus reduce operating cycles from weekly to modified weekly or even daily. That said, there may be opportunities to expand existing pumped storage projects by installing new water conveyance systems and power complex facilities. Such expansions may offer the ability to utilize energy storage (MWh) efficiency by increasing capacity and decreasing available run times. Such expansion projects could be realized with minimal impact to the operations of the existing station and take advangage of existing infrastructure such as reservoirs, access, and transmission.

3.1.4 Project Expansion–- Addition of New Units to Existing Water Conveyance Systems

Similar to Section 3.1.3, existing projects may also be expanded via the addition of new units to an existing water conveyance system; however, this alternative requires a thorough evaluation of the existing water conveyance system and the potential impacts caused by the addition of new units. The potential hydraulic impacts of higher flows include increased friction loss, potentially higher loading on trashracks, potentially increased debris transfer due to higher velocities, potential for hydraulic disurbances and potential changes in transient pressures (both maximum and minium pressures). The hydraulic design impacts need to be thoroughly evaluated along with other design considerations.

3.2 Efficiency Increases

In some instances, the ability to increase the amount of flow at the plant is non-existent. In addition, for pump-turbines, maintaining the number of hours of generating at the existing full capacity outweighs that of generating at higher capacities for fewer hours. Under these conditions, modernization possibilities are limited to efficiency improvements.

3.2.1 Runner Replacement

In terms of pure efficiency improvement, the runner remains the most significant turbine component selected for modernization consideration.

Advances in analytical, computer, and model testing techniques allow runners to be optimized for the conditions under which the pump-turbine is expected to be operated. Because runner design methodology at the time of original installation did not have the benefits of these modern techniques and computerization, the opportunity for modernization of older units, even on an efficiency increase basis only, is very realistic.

Most, if not all, pump-turbine runner replacement projects have testing of a fully homologous scale model included in the project scope. It is highly recommended such a test be included in the scope of any pump-turbine runner replacement.

Incremental Scope Considerations

Runner Seal Configuration (Medium- to High-Head Francis-Type Turbines) – Experience shows that many original turbines were installed with simple, straight seals between the rotating runner and the stationary components. Leakage losses through the runner seals can be substantially reduced by installing wearing rings of a different design and configuration. Several designs have been utilized with losses reduced by as much as 40% over the straight seal design.

3.2.2 Wicket Gates (Reaction Turbines)

Wicket gates regulate the flow of water to the runner of the turbine. Reshaping of the wicket gates can improve the hydraulic efficiency of the unit. As reshaping of existing gate leaf profiles is very difficult to perform while maintaining critical dimensional tolerances, new wicket gates are typically the preferred alternative for performance improvement. Experience shows that, in most cases of wicket gate replacement in pump-turbines, stainless steel is the material of choice for manufacture of the gates. With conventional turbines, the material is typically either entirely stainless steel or a combination of carbon steel with stainless steel on all sealing and bearing surfaces.

3.2.3 Stay Ring/Stay Vane Modifications (Reaction Turbines)

The stay ring directs the flow of water into the turbine (and out of the pump-turbine) distributor, while providing support to the distributor. It is comprised of streamlined, stationary vanes connected to upper and lower annular rings (deck plates). Modern analytical techniques have shown that existing stay vane incidence losses (for pump-turbines in both flow directions) can be reduced through profile modifications, typically consisting of extensions to the entrance edge and tapering of the discharge edge. This is especially true where the discharge rates are being increased.

In some cases, the deck plates of the stay ring have also been modified to improve the flow through the stay ring. This has been performed where the existing design consists of converging decks, where modern designs have parallel deck plates across the entire radial length of the stay vanes. This modification is performed by installing a series of deck plate sections between adjacent stay vanes.

3.2.4 Draft Tube Modifications (Reaction Turbines)

For low-head installations, the draft tube plays a significant role in recovering the residual energy leaving the runner. Again, with the growing sophistication of the analytical tools available to the turbine designer, optimized shapes of a draft tube can be developed and compared with that of an existing installation. Modifications can vary from simple additions of concrete to the floor of an elbow draft tube to the addition of horiziontal splitter vanes. Due to the individuality of draft tube configurations and applications and potential modifications, such modifications are considered beyond the scope of this report. Therefore, it is recommended that turbine manufacturers be contacted to assess possible improvements in efficiency through such modifications.

3.2.5 Optimizing Operations

The optimization of hydroelectric operations depends on a number of factors including but not limited to:

§ Market power pricing;

§ Flow or water level restrictions/demands including water rights, recreational water releases, freshnet or aquatic habitat releases, municipal water demands, reservoir level limitations, etc.;

§ Turbine and generator efficiencies;

§ Turbine, generator or governor limitations (response time, limitations on load or loading rate, limitations of number of starts/stops, maintenance or outage considerations, cavitation limitations, etc.);

§ Independent System Operator (ISO) or system grid demands; and

§ Overall river system water management.

Due to the number of variables and the complexities of management, hydroelectric operations generally utilize operations management software that can include these factors and optimize operations based on defined criteria.

3.3 Adding Capacity to Existing Non-Powered Dams, Water Supply Projects, and Irrigation Projects

The addition of generation to non-powered dams has gained momentum due to numerous green power initiatives in many states. These initiatives include state mandates for green power generation as a percentage of the total generation capacity, tax incentives for green power generation, and renewable energy credits to help encourage green power initiatives. This program has increased awareness of green power generation and provided additional incentives to make the projects more viable economically.

A 2007 study was conducted by the Department of Energy and other federal agencies to evaluate hydroelectric development potential. The report, entitled "Potential Hydroelectric Development at Existing Federal Facilities", identified six potential sites owned by the U.S. Bureau of Reclamation and 58 sites owned by the U.S. Army Corps of Engineers that satisfied physical and economic criteria, suggesting the sites had sufficient merit to warrant additional investigation for final development. The initial estimate of potential generation capacity from these USACE and USBR sites was 1,230 MW.

Municipal water supply projects that have high elevation differential between the reservoir and the water treatment plant can use mini or micro turbines instead or pressure regulating valves. These turbines recover energy that would otherwise be lost. Installations of this type have been utilized in Europe for some years and are now more common in the Western U.S. Pump derivative turbines are commonly used in these applications since the turbines can be installed in line as a direct replacement for pressure regulating valves.

Section 4: Updating and Escalating Project Costs from Prior Experience

4.1 Screening-Level Cost Opinions for Greenfield Pumped Storage Hydroelectric Development

4.1.1 Objective

The primary objective of this study element is to provide an opinion for escalating the various cost elements presented primarily within the Pumped-Storage Planning and Evaluation Guide EPRI GS-6669 (January 1990) and, to a much lesser extent, the Application of Adjustable Speed Machines in Conventional and Pumps Storage Hydro Projects EPRI TR-105542 (November 1995).

Updating and escalating techniques were developed, building on various procedures such as those developed by the U. S. Army Corps of Engineers (USACE) and U.S. Bureau of Reclamation (USBR). In addition, an internal database of recent studies and vendor/contractor quotes, inquiries seeking cost data from original equipment manufacturers and contractors, published labor and material indices, and recent completed projects (depending on the owners' approval to share such data) were utilized.

4.1.2 Commonly Utilized Escalation Techniques

As part of the initial screening evaluation of a potential greenfield hydroelectric pumped storage development, it is common practice to develop high-level project cost estimates using basic layout data and cost curves similar to those presented in EPRI 1990. The challenge is how to apply appropriate cost escalation factors to these cost curves that reflect 1988 price levels.

As an initial step to help address this challenge, Table A-1 (located in Appendix A) shows cost indices for the following sources from 1988 through 2010:

§ USACE, Civil Works Historical Construction Cost Indices (Power Plant)

§ RS Means Historical Cost Indices

- USBR Historical Construction Cost Indices (Composite)
- USBR Historical Construction Cost Indices (Equipment)
- Engineering New Record Historical Construction Indices

A comparison of these cost indices is provided in Figure 4-1.

By comparing each of the indices, one could reasonably conclude that an appropriate index factor for escalating 1988 cost to 2010 cost is in the order of 2.0. However, within the past few years, increases in the construction cost of utility infrastructure has been well documented, largely attributed to escalating costs for raw materials (e.g. cement, steel, and copper); labor; transpiration; fuels; and global demand for commodities and manufactured goods; and a weakening U.S. dollar. Recent studies indicate that simply applying an escalation factor of 2.0 may underestimate the costs to procure and construct a pumped storage facility.

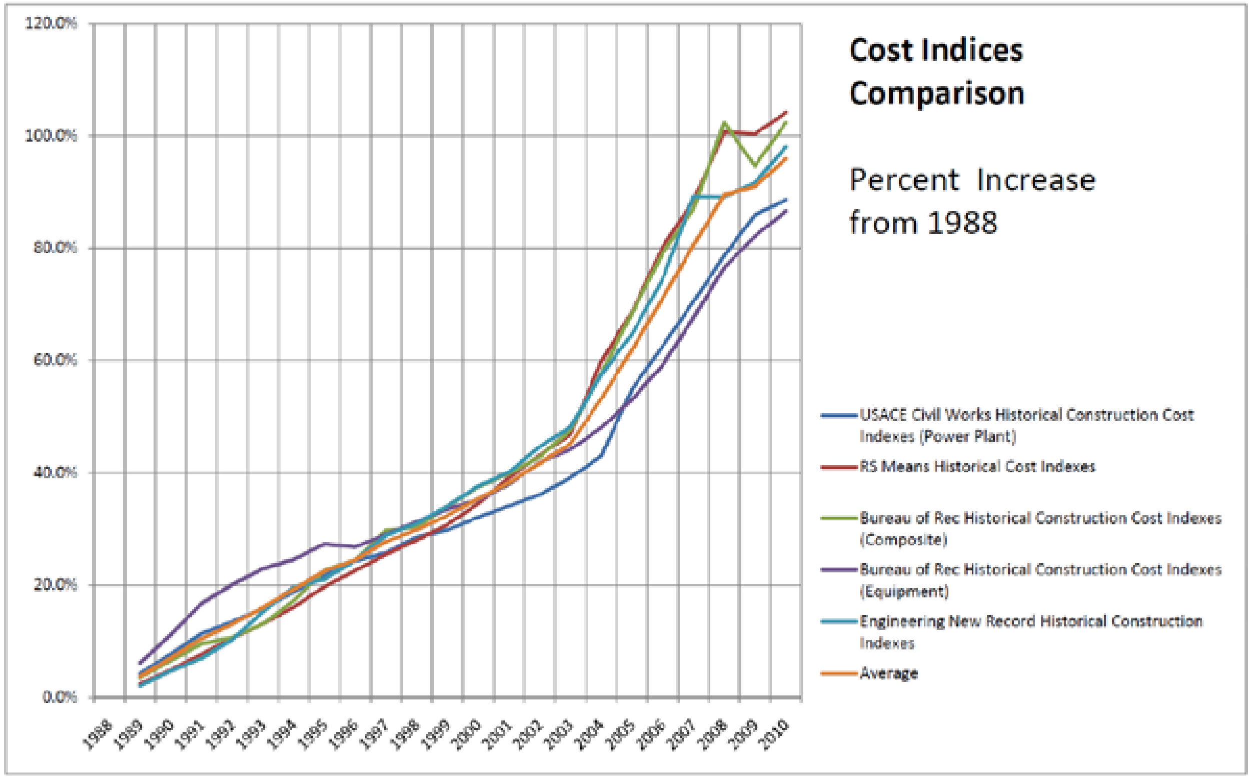

Figure 4-1
Cost Indices Comparison – Percent Increase from 1988

4.1.3 Industry Cost Trends

To better understand industry cost trends, an internal database of unit costs was utilized as well as that supplied from various major hydroelectric equipment manufacturers, constructors and subject matter experts. The result of this outreach effort yielded as-built cost data represented by the following:

§ Underground and Shoreline Power Stations – Various projects.

§ Embankments/Dams – Multiple projects

§ Intakes – Three feasibility studies (2008–2010)

§ Surface Penstock – Four as-built penstocks (2006) and two feasibility studies (2010)

§ Steel-lined Tunnels/Penstocks – Nine as-built (1999–1010)

§ Vertical Shafts, Horizontal Power Tunnels – Thirty-nine (1995–2010)

§ Underground Cavern Access Tunnels – One as-built (2006) and one feasibility study (2008)

§ Power Station Equipment – Multiple projects and input from Voith, Alstom, Toshiba, Hitachi and Andritz

§ Transmission Lines – Multiple projects

§ Contractor Unit Costs – Kiewit, Jacobs, CBI, and others

4.1.4 Study Observations (Single Speed Technology)

4.1.4.1 Direct Costs

Listed below are observations resulting from this study effort delineated by major cost elements and applicable EPRI figure.

4.1.4.1.1 Civil Works

Power Station Costs (EPRI Figures 6-8 and 6-9)

Although inclusive, the data accumulated indicate that utilizing an index factor of 2.0 for escalating power station civil costs from 1988 dollars to 2010 dollars may underestimate the cost opinion to construct a pumped storage power station. Furthermore, an index factor of 2.5 or greater may be applicable for projects having substantial head, with an index factor of 3.0 or greater for projects considered to be low-head pumped storage applications.

Dams, Spillways, Water Diversion Works, and Embankments (EPRI Figure 6-10)

Construction costs accumulated for embankments varied considerably. Discounting the cost for the concrete face rockfilled dam, the data supports a 1988 to 2010 index factor of approximately 2.8. However, it should be noted that embankment costs are extremely sensitive to hydrologic and geologic conditions.

Intakes (EPRI Figure 6-12)

The cost data accumulated for intakes supports a 1988 to 2010 index factor of between 2.0 and 3.0 (or greater for intakes considered to be civil intensive).

Surface Penstocks (EPRI Figure 6-16)

The cost data accumulated for surface penstocks is inclusive and an index factor of between 2.0 and 3.0 is recommended to escalate costs from 1988 to 2010. For surface penstocks requiring extensive civil works (e.g., excavation, ground stabilizing measures, alignment changes, or challenging climatic conditions), a greater index factor may be justified.

Vertical Shaft (EPRI Figure 6-14)

The cost data accumulated indicates that an index factor in the order of 4.0 or more is recommended for escalating the vertical shaft construction costs presented in Figure 6-14 from 1988 to 2010.

Horizontal Power Tunnels (EPRI Figure 6-13)

§ Tunnels 1 Mile or Less – The cost data accumulated for tunnels having a length of 1 mile or less indicate that the installed costs per foot of tunnel is in the order of three to six times the 1988 costs presented in EPRI Figure 6-13, indicating that an index factor of 2.0 may underestimate the cost in 2010 dollars.

§ Tunnels 1 to 2 Miles – The cost data accumulated for tunnels having a length of 1 to 2 miles indicate that the installed costs per foot of tunnel is in the order of two to five times the 1988 costs presented in EPRI Figure 6-13, indicating that an index factor of 2.0 may underestimate the cost in 2010 dollars.

§ Tunnels 2 to 4 Miles – The cost data accumulated for tunnels having a length of 1 to 2 miles indicate that the installed costs per foot of tunnel is in the order of two to five times the 1988 costs presented in EPRI Figure 6-13, indicating that an index factor of 2.0 may underestimate the cost in 2010 dollars.

- Tunnels Greater Than 4 Miles – The cost data accumulated for tunnels having a length greater than 4 miles indicate that the installed costs per foot of tunnel is in the order of two to four times the 1988 costs presented in EPRI Figure 6-13, indicating that an index factor of 2.0 may underestimate the cost in 2010 dollars.

Steel-Lined Tunnels (EPRI Figure 6-16)

The cost data accumulated for steel-lined tunnels reflects an index factor of between 3.0 and 8.0. However, as explained below, it may be inappropriate to directly compare these costs to the costs for constructing a steel lined penstock and/or steel-lined draft tube tunnel.

Discussion Regarding Collected Tunnel Data

Because no domestic pumped storage projects have been constructed within the U.S. over the past 20+ years, the tunnel data collected primarily reflects the costs of large underground infrastructure water/wastewater-type tunnel projects, which generally include the following construction features included within the tunnel costs:

- Inlet and outlet structures;
- Vertical shafts;
- Special linings;
- Varying subsurface conditions;
- Construction in populated areas;
- Additional environmental and regulatory requirements; and
- Stand-alone projects, absorbing all indirect and mobilization/demobilization costs.

As a result, one would expect the costs for these projects, aggregated on a per-foot basis, to be greater than the cost for water conveyance tunnels reflected within the EPRI figures that are a part of a much larger tunneling and/or underground construction effort for an energy complex. This may also explain the reason for the shorter tunneling efforts exhibiting the higher escalation costs.

Civil Works Conclusion

Although difficult to ascertain with certainty an escalation factor applicable for all pumped storage civil works, the data seems to indicate that one could reasonable defend an escalation factor in the order of 2.5 to 3.0.

4.1.4.1.2 Electro-Mechanical Works

The following information was solicited from various turbine-generator manufactures:

- § In general, what do you feel is a reasonable value for escalation of pumped storage power plant equipment since 1988?
- § Are you aware of any recent public bid information for new equipment that would support this value of escalation or would indicate that the 1988 cost curves are incorrect?
- § What do you feel is a reasonable adjustment for equipment costs for underground as opposed to surface powerhouses?
- § What do you feel is a reasonable adjustment for equipment costs for variable speed as compared to conventional single speed pumped storage equipment?

Listed below are the responses received.

Response OEM No. 1

After reviewing the curves with some recent projects that have been awarded, we came to the following conclusion:

First, we think the equipment cost with installations of underground vs above ground is almost identical (with the exception of specific balance of lant systems such as HVAC, smoke removal, and dewatering). There is really no good reason why they should not be as only the civil part will be affected.

In general, we only had high-head/high MW comparisons as we do not know of any low-head/low MW pumped storage project that was recently built. But I would suspect that these being larger in size are more affected by price changes. Consequently, the index would be higher than 2 for low-head and smaller outputs.

When looking at the high-head/high MW (4x300MW 2000ft), we noticed that the index factor of 2.0 in comparison to 1988 is very close to reality.

When we look at the cost of adjustable speed units, we see the following close correlation. The difference between constant and adjustable speed is the price of the generator. In other words, the generator price doubles for adjustable speed. This includes all additional equipment necessary for adjustable speed operation. Further, if we look at the entire equipment (turbine/generator/hydromechanical/balance of plant) cost including installation, the increase is approximately 33% for an adjustable speed unit vs conventional. Example: if per your curves a high-head conventional unit would cost $220/kW today, then adding adjustable speed would cost about $293/kW, assuming at least three units in a station. Single adjustable speed units are considerable more expensive.

Response OEM No. 2

According to our statistics, recent projects reflect a price increase factor of approximately 95% to 115%, comparing with values of the EPRI graphs.

From similar statistics, the price increase for variable speed was about 40%, comparing with single speed

Response from OEM No. 3

The tabulated information from USBR, USACE, et al., in summary seem to indicate that the current price of pumped storage equipment for new plants in the U.S. would be 200% of that in 1988. We believe that likely underestimates the increase in material costs in recent years, but would note that there have been few if any major new pumped storage projects awarded in the U.S. during this time. Therefore, as you suggest, predictions must be made only a cost basis vs correlating to a market basis. We would estimate this multiplier as being perhaps in the 250-275% range.

We believe the differential between equipment for a surface powerhouse vs. an underground powerhouse is very site-specific, to the point that a consistent multiplier is probably not reliable. However, if a guideline is to be produced, we wouldn't think that the difference on a percentage basis has changed much since the last EPRI update.

There are many variables/options available for "variable speed," as well as many site variables. A single multiplier/ratio of costs compared to conventional single speed pumped storage units is probably not reliable, and our recommendation is that each case should probably be looked at individually, based on its specific requirements.

Response from OEM No. 4

§ In general, what do you feel is a reasonable value for escalation of pumped storage power plant equipment since 1988?

There are two ways to consider this escalation. One is actual cost of material while the other is the value of the U.S. dollar along with currency exchange related to the Original Equipment Manufacturer. Steel costs can be easily tracked and play a major role in equipment pricing. In a small window tracking from mid-2003 to end of 2004, we experienced in increase in steel pricing of over 60% just for that short time period. We have noted, however, an overall 5-10% reduction of equipment pricing starting 2009 reacting to the U.S. recession. Probably more significant is the drastic change in exchange rate. The Japanese Yen to U.S. dollar on January 1, 1990 was $146.25 while on January 19, 2011 it was $82.07. This exchange rate alone indicates a significant cost increase for power plant equipment coming into the U.S. from Japan.

- Are you aware of any recent public bid information for new equipment that would support this value of escalation or would indicate that the 1988 cost curves are incorrect?

  Hydro equipment for new, greenfield installation in the U.S. has been almost negligible for the past 10 years. During this time, most equipment purchases have been for upgraded or rehabilitated units. This typically includes turbine components (runner, wicket gates, head covers, etc.) and not the major components like the spiral case, penstock, turbine casing, etc. Therefore, since no new pump-turbines have been quoted recently, it is difficult to confirm/deny the value of escalation.

- What do you feel is a reasonable adjustment for equipment costs for underground as opposed to surface powerhouses?

  As an equipment supplier, there is very little difference in pump-turbine equipment supplied for an underground vs a surface powerhouse. Most of the cost differential is related to civil and balance of plant systems. There are also specific differences in auxiliaries as well as requirements for ventilation and/or fire suppression especially if underground powerhouses contain the generator step-up transformers.

- What do you feel is a reasonable adjustment for equipment costs for variable speed as compared to conventional single speed pumped storage equipment?

  From the pump-turbine side, there is little difference between variable speed and single speed equipment. The cost adjustment is mainly related to the generator-motor and is dependent upon the technology used for controlling the variable speed unit. There are also many other variables that must be taken into consideration including head and speed. You can safely assume that variable speed generator motor is more expensive than single speed, possibly up to the 2X range for the generator only. However, it is important to weigh the advantages of a variable speed unit including stabilization of load (Automatic Frequency Control - AFC) within pumping mode and improvement of network stability. These advantages can be significant for specific customers that require such system control within their generation portfolio.

Electro-Mechanical Works Conclusion (EPRI Figures 6-17 and 6-18)

According to the vendor community as well as engineering experience, an escalation factor of between 2.0 and 2.75 appears to be reasonable for single speed equipment. For variable speed equipment, a premium of between 30% and 40% is recommended.

4.1.4.1.3 Transmission Works (EPRI Figure 6-21)

An extensive transmission data base was utilized to estimate the following average transmission line construction costs in 2010 dollars:

- 115 kV: $175K - $350K per mile
- 138 kV: $200K - $400K per mile
- 230 kV: $300K - $500K per mile
- 345 kV: $700K - $1.5M per mile
- 500 kV: $1.2M - $2.0M per mile

When compared to EPRI Figure 6-21, these costs represent an average escalation factor in the order of 3.0.

4.1.4.1.4 Switchyard (EPRI Figure 6-20)

Switchyard costs vary relatively linearly based on the size and number of units. A 2011 switchyard project provided a cost of approximately $57,000/MW for a five-unit, 446 MW plantar 230 kV. However, costs follow a second order polynomial based on the interconnect voltage. With 115 kV serving as the base, the normalized cost curve is approximately as shown in equation shown below.

$$Cost\ (V) = 3.19 * 10^{-5}V^2 - 7.76 * 10^{-3}V + 1.45$$

Where V is the switchyard interconnect voltage in kV.

Switchyard costs have increased due to the same global market and commodities forces discussed in Section 4.1.2. Switchyard costs are especially sensitive to increases in the price of copper, steel, and aluminum.

4.1.4.2 Indirect Costs

Previous EPRI studies indicate that indirect costs generally range between 15% to 30% of the total direct costs and include expenditures for planning studies, environmental impact studies, investigations, licensing and permitting applications, processing of applications, preliminary and final design, quality assurance, construction management, and administration. Furthermore, 20% is recommended for project perceived as being of normal complexity. For complex projects, EPRI recommends a high allowance. For the purpose of this study, an allowance of 25% for normal projects and 30% for complex projects, reflecting increasing environmental and regulatory constraints, is recommended.

4.1.4.3 Contingency

Previous EPRI studies recommend the following contingency allowances be applied to direct costs to account for unforeseen, unknown and/or omitted cost elements:

- 25% for electrical/mechanical and civil structures, and
- 35% for underground works.

This recommendation remains appropriate.

4.1.4.4 Other Cost Elements

In addition to the capital cost elements noted above, the developer may need to include in pro-forma development the cost for transmission interconnections, infrastructure upgrades, initial charging energy and/or initital reservoir filling, pumping, life cycle operations and maintenance, time cost of money, escalation for labor/material, interest during construction, escalations, depreciation, bank fees, and other factors determined applicable.

4.1.4.5 Life Cycle Costs

4.1.4.5.1 Annual O&M Costs

Previous EPRI studies provide the following equation for estimating the annual operations and maintenance (O&M) costs for a pumped storage project in 1987 dollars:

O&M Costs ($/yr) = $34{,}730 \times C^{0.32} \times E^{0.33}$

Where: C = Plant Capacity, MW

E = Annual Energy, GWh

This methodology is considered valid and an escalation factor of 2.5 is recommended. In addition, the following additional annual costs are recommended:

- Annual general and administration expenses in the order of 35% of site specific annual O&M costs, and
- Annual insurance expenses equal to approximately 0.1% of the plant investment costs.

4.1.4.5.2 Bi-Annual Outage Costs

Bi-annual outages are recommended at the very least. Annual inspections are preferred. The need for repair following inspections can vary depending upon such variables as how the units are operated, how many hours per year the units will be on-line, how much time has elapsed since the last inspection/repair cycle, the technical correctness of the hydraulic design for site specific parameters, and water quality issues. A conservative estimate would be that the individual units will be taken out of service for approximately two to four weeks every two years for routine bi-annual inspection and maintenance. Typically cavitation repairs would be completed on the runner to restore the condition of the damaged hydraulic surfaces. Other non-destructive examinations (NDE) of key components would also be completed. An estimated cost for this level of inspection and repair would be dependent on the runner or unit size. Ranging from small to large, the cost for these inspections and repairs could vary from approximately $100,000 to $250,000. Site or machine design-dependent variables can increase the cost further.

4.1.4.5.3 Major Maintenance

Pumped storage units are typically operated twice as many hours or more per year than conventional generating units if utilized to full potential. They are limited only by power market demands and reliability. This increased duty results in the requirement to perform major maintenance on a more frequent basis.

From a major maintenace standpoint, pump-turbines can be separated into two categories: low- to medium-head and high-head projects. For low- to medium-head pump-turbines operating at 50% of more hours per year, counting both pumping and generting modes of operation, an overhaul is typically performed every 25 to 35 years. For high-head pump-turbines, an overhaul is typically performed after 15 to 20 years of operation. Overhauls typically include restorations of all bushings and bearings in the wicket gate operating mechanism, replacement of wicket gate end seals, rehabilitation of the wicket gates including NDE of high-stress areas, rehabilitation of the servomotors, replacement of the runner seals, NDE of the head cover, restoration of the shaft sleeves and seals, and rehabilitation of the pump-turbine bearing. The end result is restoring the pump-turbine to like-new running condition.

Pump-turbine inlet isolation valves will likely require refurbishment of the valve seats and seals. For low-head installations, the only isolation may be the headgates at the intake due to the relatively large size of the power tunnel. On medium-head applications, low-loss style butterfly-type valves with replaceable seats and seals are typically utilized. These are heavy duty, highly engineered, and designed specifically for the rigors of unit isolation. For higher head applications, spherical-type valves are used. These valves have head pressure-activated seals that are moved into position after the valve rotor is in the closed position. The seats and seals may require replacement during a major maintenance overhaul but typically draining of the upper reservoir is required. The valves typically have hydraulically actuated counterweights for emergency closure.

The service life of a generator-motor is generally dependent upon the condition of the insulation in the stator and rotor. The degradation of the insulation is generally a function of operating temperatures. If the generator-motor is consistently run at high loads both generating and pumping, the insulation life will be reduced. Current insulating materails are much more resistent to degradation than materials used even 30 years ago, thus the vintage of the machine is a factor. The need for reinsulation of the stator and rotor, typically of a salient pole design, can vary from 20 to 40 years depending upon the duty cycle and insulating materials utilized. Restacking or replacement of the stator core may also be indicated depending upon Electromagnetic Core Imperfection Detector (EL CID) testing, which is recommended. Generator-motor rehabilitation usually also includes an evaluation of the guide and thrust bearings with refurbishment as a possiblity. For generator-motors with air-to-water heat exchangers, replacement or refurbishment is often indicated, especially if tube leaks are a chronic problem. NDE of the high stress areas in the rotor hub/spider should also be completed.

The costs for these modifications depend on many factors. Due to the complexity of the scope, an estimate must be developed for each installation. The cost of unit disassembly and reassembly may be estimated from the graph included in Section 4.6.1. The cost for pump-turbine component refurbishment or upgrade may cost 30% - 50% of the runner cost depending on scope. The cost for reinsulation of the generator-motor is discussed in Section 4.6.3.

4.2 Pumped Storage Construction Costs Ratios

4.2.1 Objective

The objective of this study element is to provide a cost opinion data in 2010 dollars (with an expected accuracy of AACE Class 5) to assist with high-level greenfield pumped storage evalations as a ratio of the following variables:

§ Unit costs and head ($/kW/ft), similar to Figure 10 of EPRI 1990;

§ Unit costs ($/kW) versus head (ft), similar to Figure B-3, Sheet 1 of 3 of EPRI 1990; and

§ Unit costs ($/kW) versus capacity (MW), similar to Figure B-3, Sheet 2 of 3 of EPRI 1990.

Such information could provide an initial high-level cost opinion for use in conducting initial screening studies.

4.2.2 Method

A data search was performed to determine both historical and projected costs for constructing pumped storage projects in the U.S., Europe, Asia, and Africa. Information was obtained from various sources, including but not limited to the following:

§ EPRI 1990

§ Hydro Review Worldwide December 2008

§ Hydro Review Worldwide October 2010

§ HydroWorld website, various articles

§ Hydrochina website, various articles

§ Eskom South Africa website

- HYDRONEWS website, various articles
- Various OEM websites
- Internal database

4.2.3 Available Data

The results of this search effort yielded construction cost data for 34 pumped storage projects as shown in Table 4-1. All cost data was escalated to 2010 U.S. dollars using techniques identified within this report. It should be noted that the content and accuracy of the data is unknown. For example, it was not clear if 1) all data sources contained direct and indirect costs, 2) the data included costs for transmission and funds used during construction, and 3) the year of cost reference.

Table 4-1
Pumped Storage Construction Cost Data

Project	Single Speed vs. Variable Speed	Stated Capacity (MW)	Estimated Cost ($/kW)	Year of Cost	Escalation Factor to 2010	Estimated Cost 2010 ($/kW)	Maximum Gross Head (ft)	Ratio ($/kW/Head)
Projects Constructed in U.S. 1960–1988 (Single Speed; See Note 1)								
Tom Sauk	SS	350	462	1988	2.6	1,201	267	4.50
Yards Creek	SS	330	332	1988	2.6	863	760	1.14
Muddy Run	SS	855	322	1988	2.6	837	127	6.62
Cabin Creek	SS	280	404	1988	2.6	1,050	373	2.81
Seneca	SS	380	505	1988	2.6	1,313	165	7.96
Northfield	SS	1,000	288	1988	2.6	749	252	2.97
Blenheim-Gilboa	SS	1,030	321	1988	2.6	835	1,143	0.73
Ludington	SS	1,890	376	1988	2.6	978	364	2.69
Jocassee	SS	628	422	1988	2.6	1,097	335	3.28
Bear Swamp	SS	540	507	1988	2.6	1,318	235	5.62
Raccoon Mountain	SS	1,530	296	1988	2.6	770	1,042	0.74
Fairfield	SS	512	586	1988	2.6	1,524	169	9.02
Helms	SS	1,050	616	1988	2.6	1,602	1,745	0.92
Bath County	SS	2,100	639	1988	2.6	1,661	1,260	1.32

Table 4-1 (continued)
Pumped Storage Construction Cost Data

Project	Single Speed vs. Variable Speed	Stated Capacity (MW)	Est. Cost ($/kW)	Year of Cost	Escalation Factor to 2010	Est. Cost 2010 ($/kW)	Max. Gross Head (ft)	Ratio ($/kW/ Head)
New Projects Constructed or Under Construction: Europe, Asia, and Africa (Single Speed)								
Baixo Sabor, Portugal	SS	171	1,901	2008	1.1	2,091	305	6.86
Huizhou, China	SS	2,400	496	2008	1.1	545	2,067	0.26
Kannagawa, Japan	SS	2,820	1,738	2008	1.1	1,911	2,142	0.89
Lima, South Africa	SS	1,470	694	2008	1.1	763	2,087	0.37
Xilongchi, China	SS	1,200	536	2008	1.1	589	2,100	0.28
Zhanghewan, China	SS	1,020	208	2008	1.1	229	1,056	0.22
New Projects Constructed or Under Construction: Europe, Asia, and Africa (Variable Speed)								
Kyogoku, Japan	VS	600	2,267	2008	1.1	2,493	1,312	1.90
Limmern, Switzerland	VS	1,000	1,770	2010	1	1,770	2,066	0.86
Nant de Drance, Switzerland	VS	600	1,513	2010	1	1,513	233	6.49
Avce, Slovenia	VS	185	886	2008	1.1	975	1,709	0.57
New or Planned Project Expansions: Europe, Asia, and Africa (Variable Speed)								
Alqueva 2, Portugal (expansion of existing facility)	VS	240	880	2008	1.1	968	249	3.88
Tehri, India (connects two existing reservoirs)	VS	1,000	368	2005	1.3	478	755	0.63

Table 4-1 (continued)
Pumped Storage Construction Cost Data

Project	Single Speed vs. Variable Speed	Stated Capacity (MW)	Est. Cost ($/kW)	Year of Cost	Escalation Factor to 2010	Est. Cost 2010 ($/kW)	Max. Gross Head (ft)	Ratio ($/kW/ Head)
New or Planned Project Expansions: Europe, Asia, and Africa (Single Speed)								
Feldsee, Austria (connects two existing reservoirs)	SS	75	840	2008	1.1	924	1,641	0.56
Kopswerk 2 (connects two existing reservoirs)	SS	450	1,109	2008	1.1	1,220	2,684	0.45
Limberg II, Austria (connects two existing reservoirs)	SS	480	960	2008	1.1	1,056	1,198	0.88
Reisseck 2, Austria (expansion of existing facility)	SS	430	958	2010	1	958	1,950	0.49
U.S. Projects Various Stage of Study Development Not Constructed (Single Speed)								
Eagle Mountain	SS & VS	1,300	1,062	2010	1	1,062	1,572	0.68
Mokelumne	SS	1,200	2,342	2009	1.05	2,459	1,863	1.32
Red Mountain Bar	SS	900	1,851	2008	1.1	2,036	830	2.45
Mulqueeney Ranch	SS	280	1,500	2009	1.05	1,575	700	2.25
U.S. Projects Various Stage of Study Development Not Constructed (Variable Speed)								
Iowa Hill	VS	400	2,000	2010	1	2,000	1,223	1.64
Red Mountain Bar	VS	1,000	2,103	2008	1.1	2,313	830	2.79

Note 1: Thought to exclude AFUDC and transmission interconnect costs.

4.2.4 Results

The study yielded costs depicted in Figures 4-2 through 4-5. To provide a perspective with respect to data scatter and potential costs differences (2010 dollars), best fit curves are provided for the following data sets in Figures 4-2 and 4-3:

- Projects Constructed in the US 1960 – 1988 (all single speed technology);
- New Projects Constructed or Under Construction in Europe, Asia and Africa (both single and variable speed technology);
- New Planned Project Expansions in Europe, Asia and Africa (both single and variable speed technology); and
- US Projects in Various Stages of Study Development (both single and variable speed technology)

Figure 4-2 includes the cost data obtained for all projects listed in Table 4-1. Figure 4-3 includes all project data, with the exception of new or planned project expansions. The following conclusions can be obtained from the figures:

- The data depicting the ration of $/kW/ft of head is clustered within fairly tight band for projects having an installed head greater than 1000 ft.
- The $/kW/ft of head is lowest for expansion projects as would be expected.
- There is fairly tight band $/kW/ft of head for all new projects either constructed or under construction in Europe, Asia and Africa.
- US projects in various stages of study appear to have a higher ration of $/kW/head.
- Projects utilizing variable speed technology appear to cost slightly more than projects utilizing single speed technology as would be expected.
- For the purpose of high level project screening the best fit curve and associated equation depicted in Figure 4-3 provides a reasonable indication of expected construction costs (AACE Class 5), excluding the costs of transmission funds used during construction.

Figure 4-4 includes the cost data ($/kW) for all projects listed in Table 4-1 as a function of capacity (MW). Figure 4-5 includes the cost data ($/kW) for all projects listed in Table 4-1 as a function of head (ft). The conclusions that can be drawn from these figures are as follows:

- The expected unit costs for all projects is generally bound by 500 and 2,500 $/kW, with the majority cluster between 1,000 and 2,000 $/kW.
- There appears to be declining trend of unit costs ($/kW) as the capacity (MW) increases, which would generally be expected as a function of economy of scale.

It was somewhat surprising that the unit cost ($/kW) as a function of head (ft) did not show, as one would expect, a more noticeable declining trend in costs as the head increased.

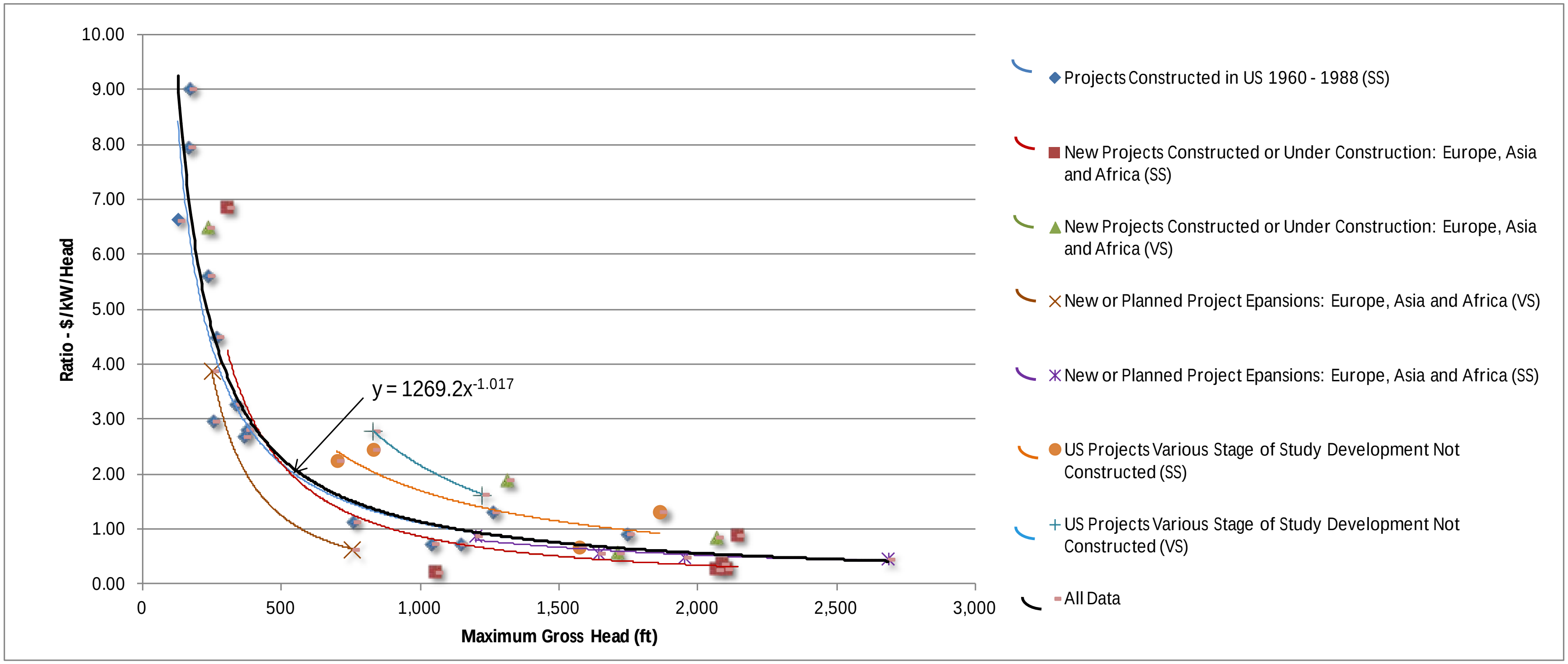

Figure 4-2
Cost Data for Projects Listed in Table 4-1

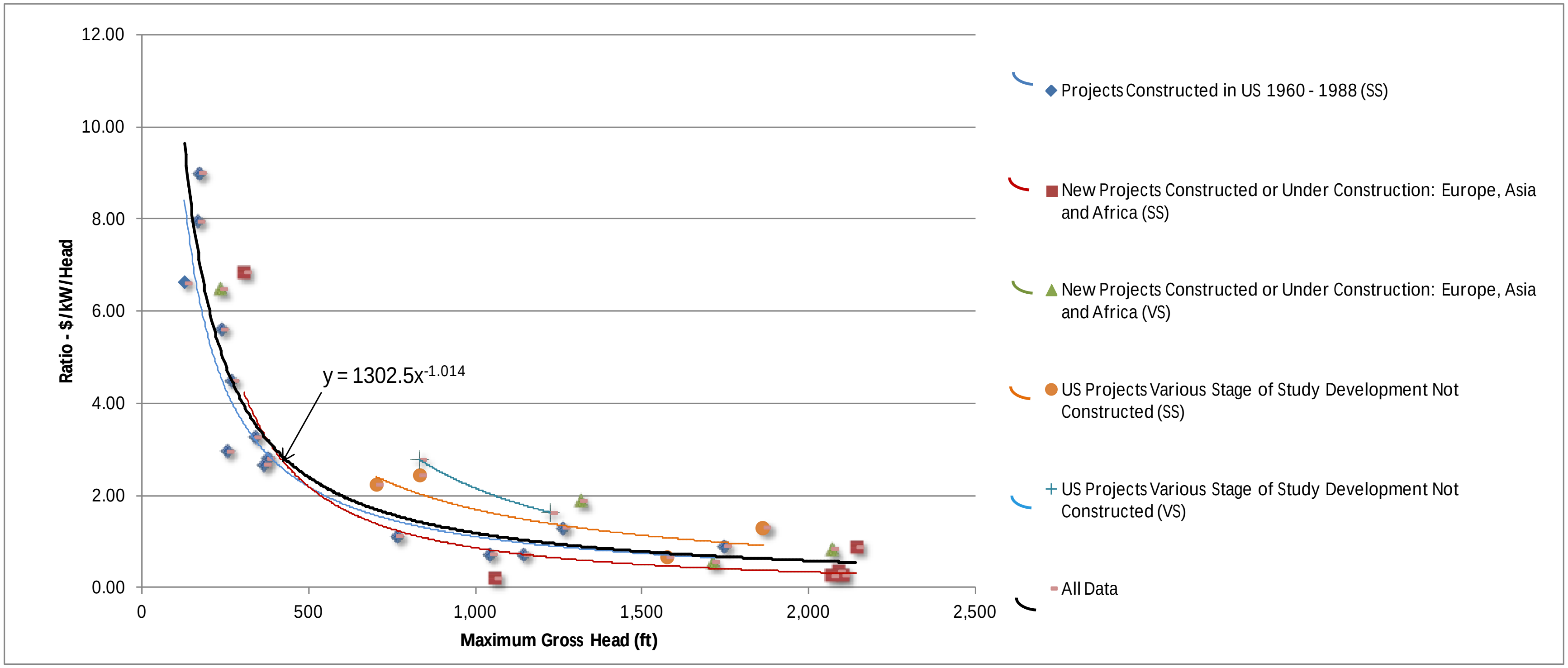

Figure 4-3
Cost Data for Projects Listed in Table 4-1 (Excluding New or Planned Project Expansions)

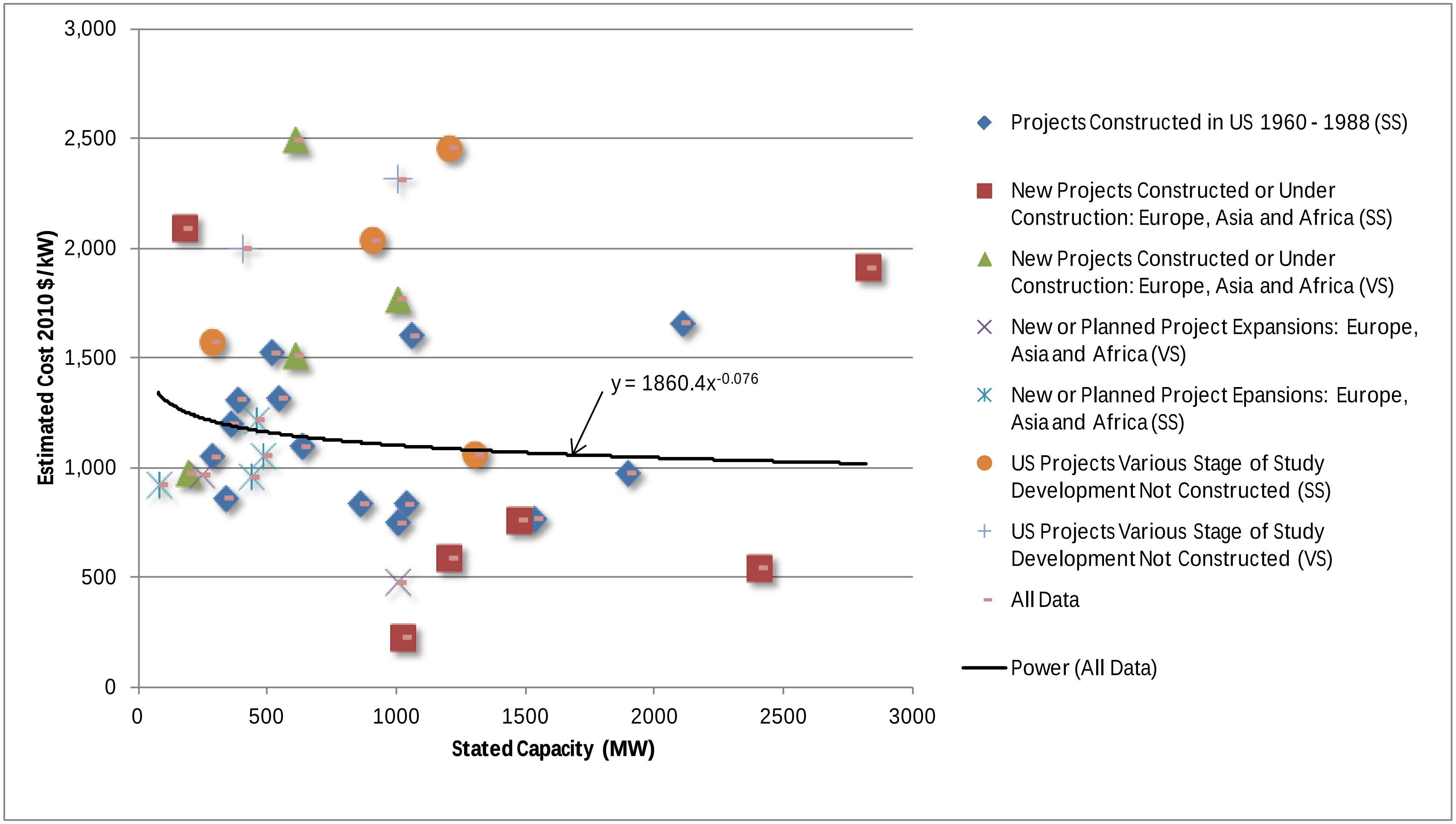

Figure 4-4
Cost Data ($/kW) for Projects Listed in Table 4-1 as a Function of Capacity (MW)

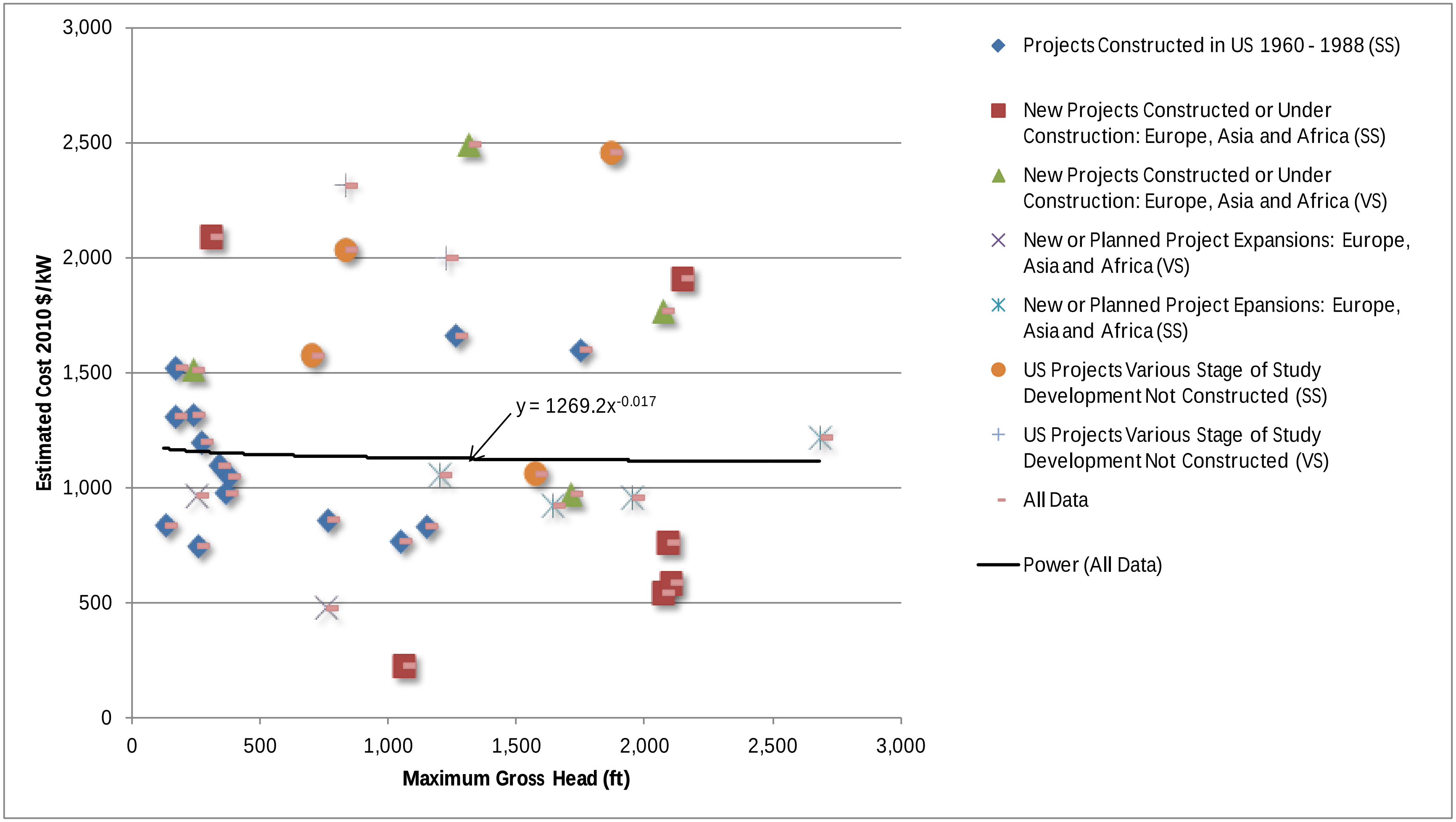

Figure 4-5
Cost Data ($/kW) for Projects Listed in Table 4-1 as a Function of Head (ft)

4.3 Screening-Level Cost Opinions for Greenfield Conventional Small, Low-Head Hydroelectric Projects (100 kW–15 MW Capacity)

4.3.1 Objective

The primary objective of this study element is to provide an opinion for escalating the various cost elements presented primarily within the document titled “Reconnaissance Evaluation of Small, Low-Head Hydroelectric Installation”, Water and Power Resources Service U.S. Department of Interior, July 1, 1980. Processes and methods similar to Section 4.1 were utilized.

4.3.2 Commonly Utilized Escalation Techniques

As part of the initial screening evaluation of a potential conventional greenfield hydroelectric development, it is common practice to develop a high level project cost estimates using basic layout data and cost curves similar to those presented in DOI 1980. The challenge is how to apply appropriate cost escalation factors to these cost curves that reflect 1978 price levels.

As an initial step to help address this challenge, Table A-2 (located in Appendix A) shows cost indices for the following sources from 1978 through 2010:

§ USACE, Civil Works Historical Construction Cost Indices (Power Plant)

§ RS Means Historical Cost Indices

§ USBR Historical Construction Cost Indices (Composite)

§ Engineering New Record Historical Construction Indices

A comparison of these cost indices is provided in Figure 4-6. By comparing each of the indices, one could reasonably conclude that an appropriate index factor for escalation 1978 cost to 2010 cost is in the order of 3.2. However, within the past few years, increases in the construction cost of utility infrastructure has been well documented, largely attributed to escalating costs for raw materials (e.g. cement, steel, and copper); labor; transpiration; fuels; and global demand for commodities and manufactured goods; and a weakening U.S. dollar. That said, recent studies performed indicate that simply applying an escalation factor of 3.2 may underestimate the costs to procure and construct a conventional green-field hydroelectric facility.

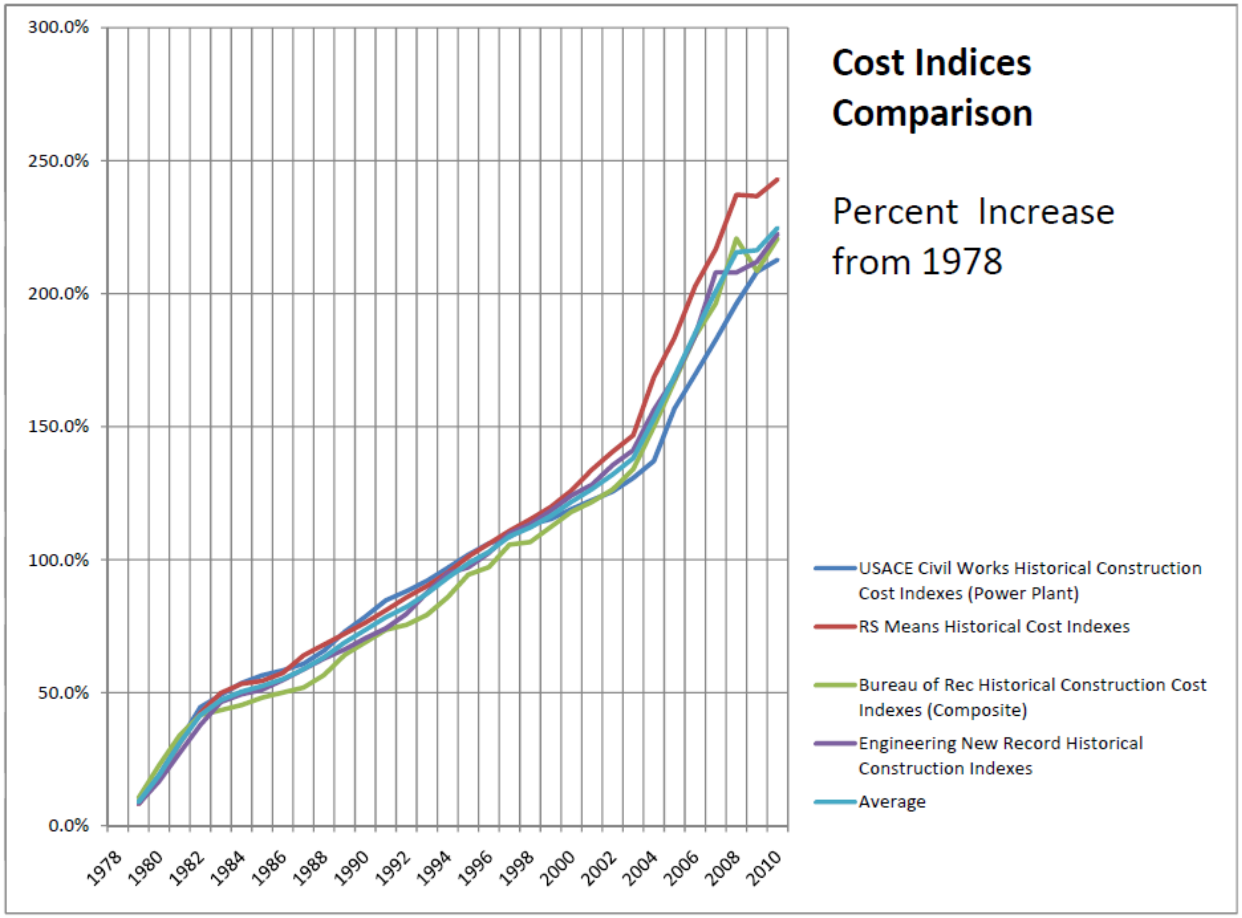

Figure 4-6
Cost Indices Comparison – Percent Increase from 1978

4.3.3 Industry Cost Trends

Refer to Section 4.1.3.

4.3.4 Study Observations

Listed below are observations resulting from this study effort delineated by major cost elements and applicable DOI figure.

4.3.4.1 Direct Costs

Turbine and Power Plant Equipment Costs (DOI Figures 5-1 through 5-9)

Data provided by the original equipment manufacturers indicates that an escalation factor of between 3.2 and 4.0 appears to be reasonable for prime mover equipment.

Powerhouse Area (DOI Figures 5-10 through 5-21)

Although inclusive, the data accumulated indicates that utilizing an index factor of 3.2 for escalating powerhouse area costs from 1978 dollars to 2010 dollars may underestimate powerhouse area cost opinion. An index factor of 3.5 is recommended for sites having favorable to average construction conditions and greater than 3.5 for difficult site conditions.

Intakes and Gates (DOI Figures 5-23 and 5-24)

The cost data accumulated for intakes supports a 1978 to 2010 index factor of between 3.2 and 4.2.

Surface Penstocks, Valves, Bifurcations, and Bypass Facilities (DOI Figures 5-25 through 5-29)

The cost data accumulated for surface penstocks and associated appurtenances is inclusive. However, for the purpose of this study an index factor of between 3.2 and 4.2 is recommended to escalate costs from 1978 to 2010. For surface penstock requiring extensive civil works (e.g., excavation, ground stabilizing measures, alignment changes, challenging climatic conditions, etc.), a greater index factor may be justified.

Dams, Spillways, Water Diversion Works, and Embankments (DOI Figures 5-30 through 5-37)

The cost data accumulated for constructing dams and embankments supports a 1978 to 2010 index factor of around 4.0. However, it should be noted that embankment costs are extremely sensitive to hydrologic and geologic conditions.

Switchyard and Transmission Costs (DOI Figures 5-38 through 5-41)

An extensive transmission database was utilized to estimate the following average transmission line construction costs in 2010 dollars:

§ 115 kV: $175K - $350K per mile

§ 138 kV: $200K - $400K per mile

§ 230 kV: $300K - $500K per mile

§ 345 kV: $700K - $1.5M per mile

§ 500 kV: $1.2M - $2.0M per mile

When compared to DOI Figures 5-38 through 5-41, the cost data accumulated for switchyard and transmission related costs support a 1978 to 2010 index factor in the order of 4.2

Grading, Drainage and Erosion Control Costs (DOI Figure 5-42)

The cost data accumulated for grading, drainage and erosion control support a 1978 to 2010 index factor in the order of 3.5

4.3.4.2 Indirect Costs

An allowance for indirect costs between 15% and 30% of the total direct costs is recommended and include expenditures for planning studies, environmental impact studies, investigations, licensing and permitting applications, processing of applications, preliminary and final design, quality assurance, construction management, and administration. Furthermore, 20% is recommended for project perceived as being of normal complexity. For complex projects, a higher allowance is recommended. For the purpose of this study, an allowance of 25% is recommended for normal projects and 30% for complex projects, reflecting increasing environmental and regulatory constraints.

4.3.4.3 Contingency

A contingency allowance in the order of 20% to 25% of direct costs is recommended to account for unforeseen, unknown, and/or omitted cost elements.

4.3.4.4 Other Cost Elements

In addition to the capital cost elements noted above, the developer may need to include in pro-forma development the cost for transmission interconnections, infrastructure upgrades, life cycle operations and maintenance, time cost of money, escalation for labor/material, interest during construction, escalations, depreciation, bank fees, and other factors determined applicable.

4.3.4.5 Annual O&M Costs

INEL 2003 provides the following relationship for estimating the annual operations and maintenance (O&M) costs for a conventional hydroelectric project in 2002 dollars:

§ Fixed O&M Costs ($2002) may be estimated by 24,000 x [Capacity MW]^0.75 and is considered to include:
  - Operation supervision and engineering
  - Maintenance supervision and engineering
  - Maintenance of structures
  - Maintenance of reservoirs, dams and waterways
  - Maintenance of electric plant
  - Maintenance of miscellaneous hydraulic plant
  - Rents

§ Variable O&M Costs ($2002) may be estimated by Costs 24,000 x [Capacity MW]^0.80 and considered to include:
  - Water for power
  - Hydraulic expenses
  - Electric expenses
  - Miscellaneous hydraulic power expenses

§ Annual General and Administrative Costs is assumed to be approximately 35% of the total O&M Costs

§ Annual Insurance is assumed to cost in the order of 0.1% of the plant investment costs

§ Annual FERC charges are assumed to be (0.1125 x Annual Generation MWH + Capacity KW) (CFR18 2008)

To obtain annual O&M costs in 2010 dollars, both the fixed and variable O&M costs should be multiplied by approximately 1.4 (approximate index factor for escalating 2002 cost to 2010 cost).

4.4 Screening-Level Cost Opinions for Greenfield Conventional Micro-Hydroelectric Facilities (<100 kW Capacity)

A micro-hydropower system is generally classified as having a generating capacity of less than 100 kW. Regarding the cost of a micro-hydropower system, there is no standard answer to this question because costs are heavily dependent on site conditions. In general, with current technologies, the total cost can range from $2,000 to $8,000 per kW of installed capacity, depending on the system's capacity and location. Table 4-2 provides an opinion of typical cost elements that could reasonably be associated with the development of micro-hydro installations.

Table 4-2
Opinion of Probable Cost Elements for Micro-Hydro Facilities

Project Site: TBD	
Typical Equipment Alternative: TBD	
Typical Installed Capacity: TBD kW	
Preparation of Final E/M Design	$
Permitting/Mitigation	$
FERC Small Conduit License Exemption	$
FERC Qualifying Facility Self Certification	$
Interconnection Application	$
FERC Small Conduit License Exemption	$
Other Permits and Miscellaneous Fees	$
Legal Fees	$
Acquisition of Access and Rights of Way	$
Cost of Project Components	
Power Transmission	
Interconnection Costs	$
Service Transformer	$
Secondary Service, Disconnect and Metering	$
Hydropower Plant	
Turbine Generator & Controls Supply	$ See Comment 1
T/G Installation and Other E/M Modifications	$ See Comment 2
SCADA Input	$ See Comment 3
Structural and Site Work Allocation	$ See Comment 4
Mob and Demobilization	$
Temporary Facilities and Equipment Rental	$
Miscellaneous	$
Subtotal Project Components	$
Field & Technical Support @ 10% of Above Subtotal	$
Profit, Insurance, Bonds, etc. @ 15% of Above Subtotal	$
Subtotal	$
Contingency @ 20% of Above Subtotal	
Total Construction Costs	$
Total Project Costs ($)	$
	$ See Comment 5

Comment 1: The supply costs for the turbine, generator, and controls package (refer to Figures 4-7 and 4-8, and Tables 4-3 and 4-4) can range from $1,000/kW to $2,000/kW depending on the unit type, operating head/flow range, and required protections. Turbines are assumed to be Cornell type, in-line horizontal direct drive configuration. Generators are assumed to be induction type.
Comment 2: Equipment installation can range approximately 50% (+/-) of the equipment supply costs.
Comment 3: SCADA input can range approximately $10,000 to $15,000.
Comment 4: As a rule of thumb, the civil works costs should be less than or equal to the equipment costs.
Comment 5: The total project costs can range approximately $2,000/kW to $8,000/kW depending on specific site characteristics and impacts to existing infrastructure.

The supply costs given in Comment 1 in Table 4-2 are based on experience with micro-turbines and controls costs based on prior in-line energy recovery/micro-hydro projects. Figures 4-7 and 4-8 provide a visual representation with respect to cost versus unit output and cost versus head. The data corresponding to these figures are presented in Tables 4-3 and 4-4.

Figure 4-7 provides a graphical representation for “Low-Head” micro and small hydro applications. “Low Head” in this case is defined as approximately 200 feet or less. The data associated with each point shown in this figure is provided in Table 4-3. For the range of applications in the micro-hydro classification, 100 kW or less, the graph indicates a range of turbine-generator and controls cost per kW output of approximately $700/kW to $2,200/ kW. The mean is approximately $1,200/kW to $1,400/kW. This range represents the cost for turbine-generator and controls equipment only. Additional cost components must be considered on a site to site basis.

Figure 4-8 and the associated data provided on Table 4-4 are included to show how cost per kW can vary for the different kind of turbines (Turgo and Pelton), as well the effect of head on cost. As can be seen in the graphs, in general as head increases the cost per kW decreases.

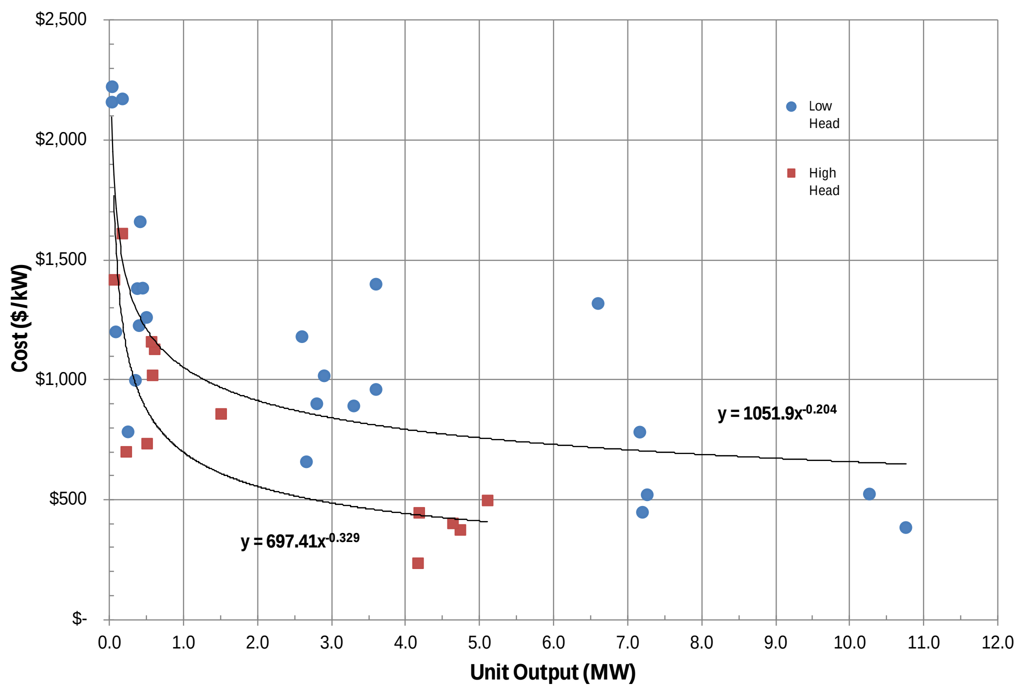

Figure 4-7
Cost Versus Unit Output

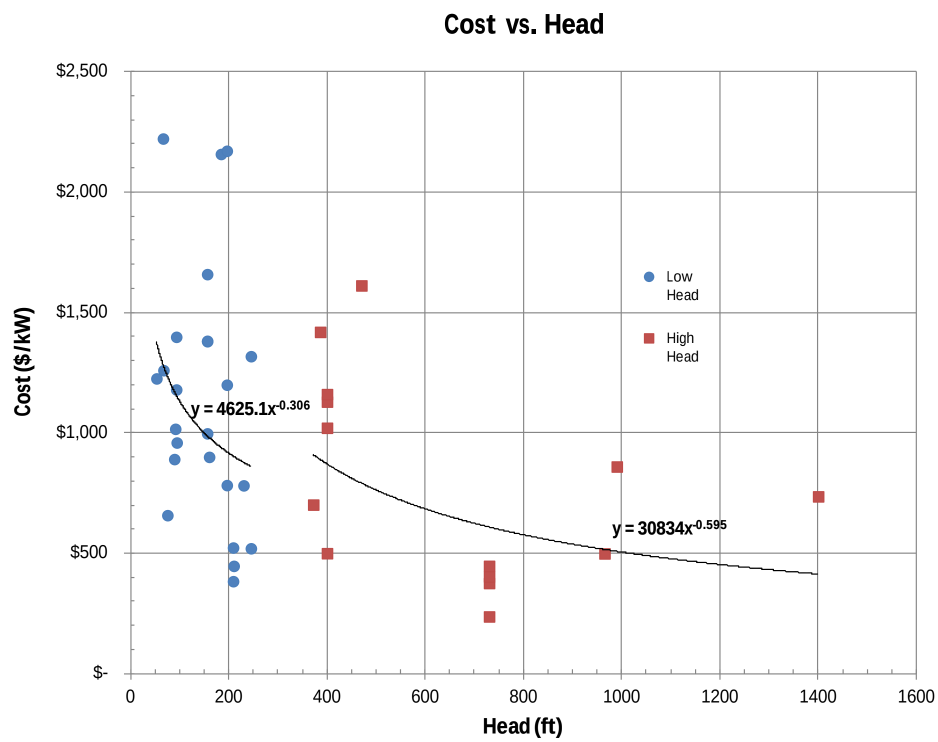

Figure 4-8
Cost Versus Head

Table 4-3
Low-Head Data

Year	Type	Orientation	Output (MW)	Flow		Net Head		Speed (rpm)	Cost (Total)	Unit ($/kW)
				(cms)	(cfs)	(m)	(ft)			
2007	Francis	Vertical	7.20	12.6	445	64	210	450	$3,221,000	$447
2007	Francis	Vertical	3.30	14.2	501	27.1	89	300	$2,940,000	$891
2004	Francis	Horizontal	2.66	13.0	459	23	75	300	$1,750,000	$658
2009	Pump Derivative	Horizontal	0.04	0.3	9	20.1	66	1,200	$80,000	$2,222
2010	Francis	Vertical	2.80	6.5	230	49	160	450	$2,520,000	$900
2011	Cross Flow	Horizontal	0.50	3.1	110	20.4	67	212	$630,000	$1,260
2007	Francis	Vertical	2.60	9.9	350	28.4	93	300	$3,067,606	$1,180
2008	Francis	Horizontal	2.90	11.9	420	27.7	91	360	$2,948,000	$1,017
2009	Francis (2)	Vertical	3.60	14.2	500	28.5	93	400	$5,035,180	$1,399
2009	Francis (2)	Vertical	3.60	14.2	500	28.7	94	300	$3,454,590	$960
2009	Francis	Vertical	10.27	18.7	660	63.64	209	300	$5,374,000	$523
2009	Francis	Vertical	10.76	18.7	660	63.6	209	514	$4,128,000	$384
2010	Francis	Vertical	7.26	9.9	350	74.7	245	300	$3,780,000	$520
2010	Francis	Vertical	6.60	9.9	350	74.7	245	514	$8,700,000	$1,318
2010	Francis	Vertical	7.16	9.9	350	70.1	230	514	$5,600,000	$782
2010	Crossflow	Horizontal	0.38	1.0	35	70.1	156	450	$519,000	$1,380
2010	Francis	Horizontal	0.45	1.0	35	70.1	156	900	$619,620	$1,382
2010	Crossflow	Horizontal	0.35	0.3	10	70.1	156	450	$349,187	$ 998
2010	Francis	Horizontal	0.41	1.0	35	70.1	156	1,200	$687,503	$1,659
2010	Crossflow	Horizontal	0.40	3.4	120	16.1	52.7	185	$490,347	$1,226
2010	Pump Derivative	Horizontal	0.03	0.1	3	56.1	184	1200	$73,375	$2,158
2010	Crossflow	Horizontal	1.25	1.1	40	121.9	400	600	$625,000	$500
2010	Pump Derivative	Horizontal	0.09	0.15	5.4	59.7	196	1,800	$101,980	$1,200
2010	Turgo	Horizontal	0.25	0.36	12.6	59.7	196	900	$195,700	$783
2010	Crossflow	Horizontal	0.18	0.34	12	59.7	196	600	$380,000	$2,171

Table 4-4
High-Head Data

Year	Type	Orientation	Output (MW)	Flow		Net Head		Speed (rpm)	Cost (Total)	Unit ($/kW)
				(cms)	(cfs)	(m)	(ft)			
2009	Pelton	Horizontal	0.165	0.15	5.3	143	470	900	$266,000	$1,612
2009	Pelton	Horizontal	0.50	0.15	5.3	427	1400	1,200	$368,000	$736
2011	Pelton	Horizontal	0.60	0.57	20	122	400	514	$680,000	$1,130
2011	Turgo	Horizontal	0.57	0.57	20	122	400	1,200	$586,000	$1,021
2011	Pelton	Horizontal	0.56	0.57	20	122	400	450	$650,000	$1,161
2010	Pelton	Horizontal	1.50	0.51	18	301	990	720	$1,290,000	$860
2007	Pelton	Vertical	5.10	2.00	70.7	294	965	720	$2,545,000	$499
2010	Turgo	Horizontal	4.73	2.69	95	222.5	730	900	$1,779,579	$376
2010	Turgo	Horizontal	4.63	2.69	95	222.5	730	900	$1,868,525	$403
2010	Pelton	Horizontal	4.18	2.69	95	222.5	730	360	$1,868,525	$447
2010	Pelton	Horizontal	4.16	2.69	95	222.5	730		$987,000	$237
2010	Pump Derivative	Horizontal	0.218	0.26	9.2	113.4	372	1,800	$153,000	$702

4.5 Cost Opinion Considerations

Cost opinions developed from material and data presented in this report should be considered as either a Class 5 or Class 4 estimate in accordance with the Association for the Advancement of Cost Engineering (AACE), primarily depending on the level of project definition and engineering completed to date. Listed below are the basic definitions of AACE Class 5 and Class 4 cost estimates:

AACE Class 5 Cost Estimates

§ Level of Project Definition: Between 0% and 2% complete

§ End Usage: Concept screening

§ Methodology: Capacity factored, parametric models, judgment, or analogy

§ Expected Accuracy Range: Low = -20% to -50%; High = +30% to +100%

§ Class Definition: Class 5 estimates are generally prepared based on very limited information, and subsequently have very wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systematic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and very little effort expended, sometimes requiring less than 1 hour to prepare. Often, little more than the proposed plant type, location, and capacity are known at the time of estimate preparation.

§ End Usage Definition: Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, and other purposes.

§ Estimating Methods: Class 5 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operation factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques.

AACE Class 4 Cost Estimates

§ Level of Project Definition: Between 1% and 15% complete

§ End Usage: Concept or feasibility study

§ Methodology: Equipment factored or parametric models

§ Expected Accuracy Range: Low = -15% to -30%; High = +20% to +50%

§ Class Definition: Class 4 estimates are generally prepared based on very limited information, and subsequently have very wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from

1% to 5% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams for main process systems and preliminary engineered process and utility equipment lists.

§ End Usage Definition: Class 4 estimates are prepared for a number of purposes, such as but not limited to detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.

§ Estimating Methods: Class 4 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques.

4.6 Cost Estimates for Modernization of Hydroelectric Facilities

Care must be taken in using the results from generic curves, tables, and processes such as those given in these guidelines, because these results are only approximations. Each plant and each individual unit has its own unique situation that requires consideration before using the information provided in this section.

Cost estimates are usually not as accurate as the technical estimates of capacity and efficiency increases; bids for replacement runners and related scope items may vary by as much as 100%. A major uncontrollable factor which influences cost and delivery time is the backlog of work in the manufacturer's plant. Therefore, the costs and delivery times presented herein should only be used as general guidelines.

The estimates derived from this section can be used for conceptual level studies of modernization of hydroelectric units. More detailed cost estimates, which are required for feasibility level studies and the project approval stage, should involve input from manufacturers.

4.6.1 Replacement Runner Costs

In this section, runner modernization costs are subdivided into the following four items:

§ Model development tests;

§ Runner supply (design, manufacture, and delivery);

§ Installation; and

§ Commissioning and final testing.

In addition, the installation of a new runner may be combined with the following other modifications to improve turbine performance, as described in Section 3:

- Stay vane/stay ring modifications on reaction turbines to better align flow entering the wicket gates,
- Wicket gate replacement on reaction turbines to improve hydraulic profile,
- Wearing ring (runner seal) design modifications on high-head Francis-type units to reduce seal losses,
- Discharge ring extensions on Francis-type units to allow a longer runner band and more blade surface area,
- Discharge ring diameter increases on axial flow turbine modernization projects with increased runner diameters,
- Draft tube modification on reaction turbines to reduce losses, and
- Nozzle enlargements on Pelton and Turgo turbines.

Field machining may be required for embedded turbine components to correct out-of-roundness, misalignment, concrete movement, or other causes. Post disassembly checks for concentricity, plumb and parallelism of turbine component mounting surfaces should be considered a requirement; especially for older vintage machines. Field machining to correct out of tolerance readings will greatly facilitate assembly and is recommended for outage risk mitigation. Those improvements are site and case dependent and require expert assessment by inspection and measurements of the dismantled machine and are not covered in detail in these guidelines.

Item A - Model Development and Test Costs

The cost to design, construct, and test a homologous turbine model is approximately $500,000 to $900,000 depending on the specific tests performed. These costs pertain to Francis, propeller, or Pelton turbine models. The cost for a Kaplan or pump-turbine model test will be approximately 10% higher. These costs include fabrication of the complete model turbine.

For runner upgrades, some owners prefer to conduct a model test on the existing runner as well as the new runner. This allows the incremental efficiency improvement of the runner upgrade to be determined with considerable accuracy. The added cost to perform a model test on the existing runner is between $100,000 and $150,000.

Because the costs for model testing are relatively high, and less expensive analytical methods are available to accurately design replacement runners, Owners often elect not to perform model tests for small capacity turbines (<50 MW). Owners should consider the costs and benefits of model development tests to determine whether they should be performed. Computational Fluid Dynamics (CFD) has facilitated detailed examination of the characteristics of fluid flow and optimization of runner design. CFD has improved dramatically over the last few years and, in many cases, can be substituted for physical hydraulic model testing; however, it must be understood that the accuracy level is still not that of physical testing. The investment required for physical testing is often not justified for units of less than 50 MW capacity (unless upgrade of several identical units is contemplated), and CFD is often being used in place of model testing for this category of turbine.

For a plant with multiple units of relatively high capacity (>100 MW), a competitive model test program is sometimes implemented. With this approach, two or more manufacturers design and test model turbines, with a final test of all designs conducted at an independent laboratory. The selection of the preferred manufacturer is made after the final model test. The owner typically covers the costs of all participating manufacturers and the overall model test program, which can cost from $1,300,000 to $1,800,000.

Item B – Cost for Design and Manufacture of a New Runner

The cost of a new turbine runner, as a function of diameter, is shown on Figure 4-9. These costs are for a new runner, designed specifically for the project. The Kaplan runner cost includes new runner blades and a new hub with blade operating mechanism. In some cases, the existing runner hub can be retained. Hub replacement will be required if:

§ There is physical damage to the hub and blade trunnion bearing supports,

§ The manufacturer's design has a smaller diameter hub which allows increased flow/output,

§ The number of blades is reduced (such as from six to five blades or five to four), or

§ There are changes to the blade servo operating system.

Changing the number of runner blades requires detailed investigation and model testing and is beyond the scope of these guidelines.

The same curve applies for Francis type conventional turbine runners and pump-turbine runners. Typically a conventional Francis type turbine runner will have twice as many blades or more than a pump-turbine runner. The pump-turbine runner blade designs, however, typically have longer vanes that have almost twice as much surface area. Consequently, past experience has shown the difference in cost to be within the intended accuracy of the graph.

The cost data in Figure 4-9 is for one runner and is in 2010 U.S. dollars. The costs for subsequent units will be lower because “one-time costs” such as design, patterns for castings, and other tooling costs are independent of quantity and turbine size, and can be distributed over subsequent units. Therefore, when four to eight runners are purchased that have the same design, the cost per runner can be reduced from 10% to 20%.

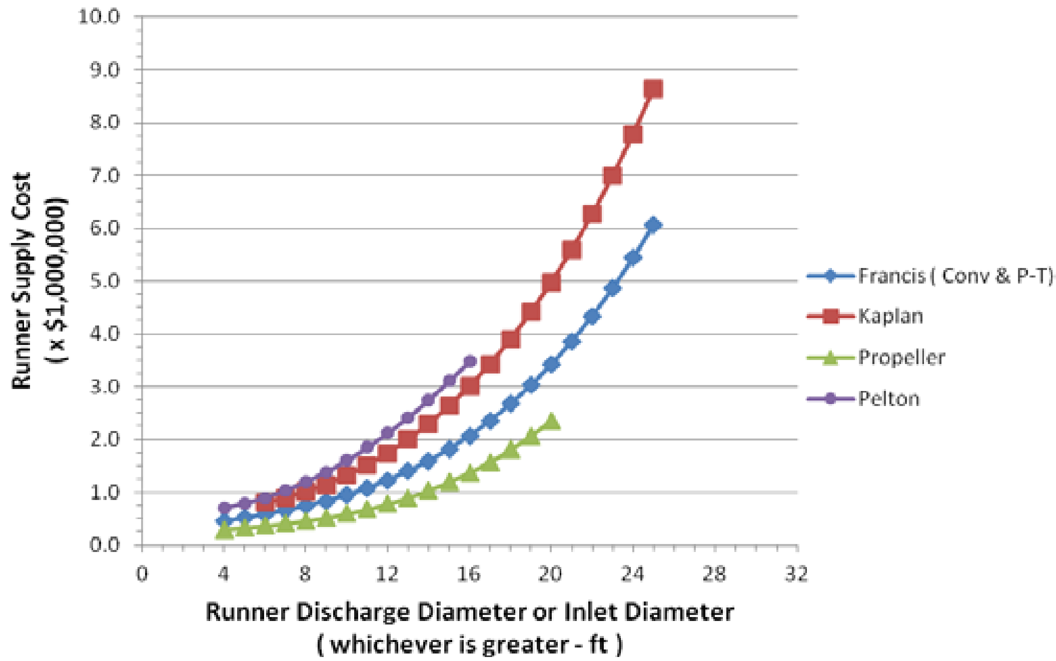

Figure 4-9
Runner Costs

Item C - Installation Cost

If the old runner is the only component that must be replaced, down time can be reduced to a minimum of 6 to 12 weeks. However, for Kaplan applications, when runner blades are replaced, the old runner may require shipping to the manufacturer's shop to properly balance the runner and overhaul the hub, which could add up to an additional two months of downtime. A new hub should be considered if the savings in unit downtime and shipping costs exceed the cost of a new hub.

Typically, turbine components will be refurbished or upgraded to modern standards during an outage to replace a runner. The turbine components are removed and shipped to the runner manufacturer's shop. Once received, work performed on these components may require from 6 to 12 weeks also, depending upon shop loading at the time. This work is typically critical path. Other activities may be perfromed in parallel such as field machining of the turbine component mounting surfaces.

The cost of installation depends on an owner's ability to support the work. For example, installation supervision provided by a runner manufacturer may cost approximately $1,000 per day. Generally, runner upgrading is combined with a general overhaul of the turbine, and therefore, the installation cost is often incorporated with the overhaul costs. However, sometimes the total unit dismantling and reinstallation costs must be included as part of the runner upgrade. If this is the case, the cost for dismantling and reinstallation including runner installation can be estimated from EPRI Figure 4-9. These costs apply to a vertical unit where the generator and turbine must be dismantled for runner installation. For a unit where the runner can be removed from below the turbine distributor or from between the turbine and the generator, or for horizontal units where the runner can be removed without dismantling any of the generator, the runner installation costs can be assumed as 10% to 25% of the runner supply cost, depending on the complexity for installation.

Item D - Commissioning and Final Testing Costs of Upgraded Units

The cost of unit commissioning includes placing the upgraded turbine into operations and verifying the performance guarantees by field tests. Commissioning tests usually require a supervisor from the manufacturer, two engineers, and necessary test instrumentation. The tests are conducted over a two-week period and require the following costs (Table 4-5; Figure 4-10).

Table 4-5
Commissioning Costs

Description	Cost per Unit
Verify Output Guarantee	$10,000
Index Test	$10,000–$20,000
Efficiency Test on High-Head Turbines	$30,000–$60,000 / test
Efficiency Test on Low-Head Turbines	$40,000–$100,000 / test

Source: EPRI 2000a

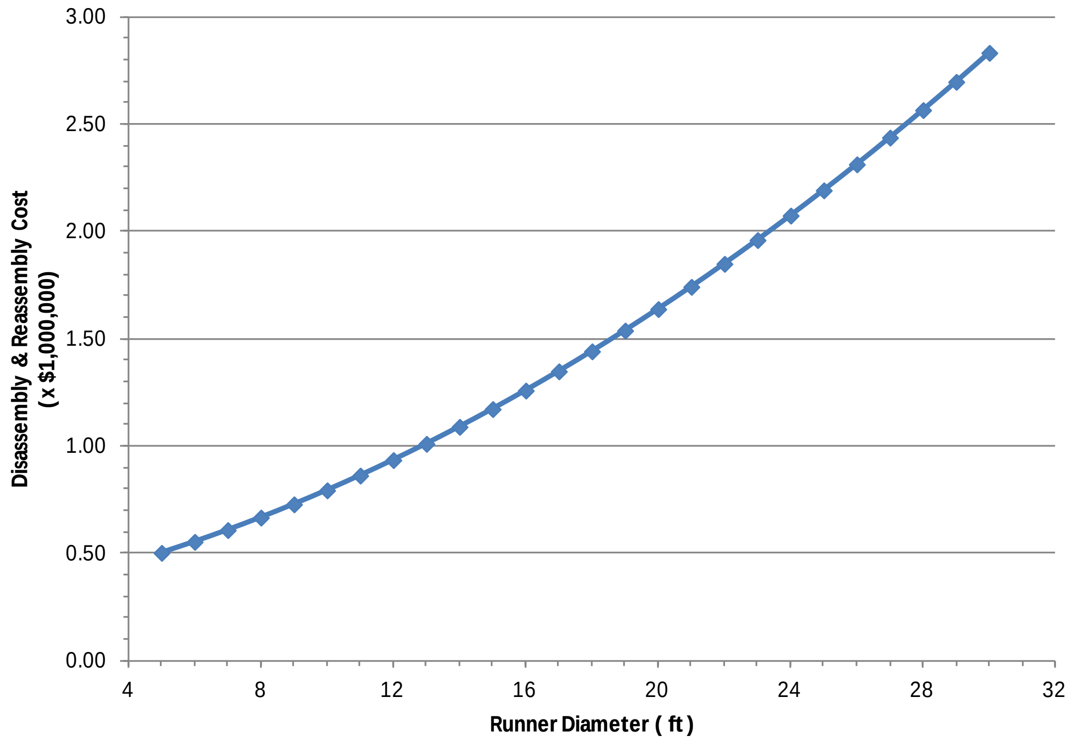

Figure 4-10
Unit Disassembly and Reassembly Cost

4.6.2 Costs of Other Modifications of a Turbine or Pump-Turbine Modernization

As discussed earlier, a runner upgrade is typically accompanied by other component modifications to further enhance the capability of the unit. In most cases, costs of these modifications include both a supply and installation component.

Stay Vane/Stay Ring Modifications (Reaction Turbines)

The cost for the modifications is highly dependent on the extent of the changes to the stay vane profile. However, as a rough guide, stay vane modifications can be estimated as 20% of the runner supply cost.

Wicket Gate Replacement (Reaction Turbines)

The cost for new wicket gates is highly dependent upon the materials utilized (e.g., carbon or stainless steel) in the manufacture and whether the gates are fabricated or cast. For estimating purposes at this stage in the modernization analysis, the cost of a set of new wicket gates can be estimated as 30%-40% of the runner supply cost.

Wearing Ring (Runner Seal) Design Modifications (Francis Units)

Runner seal modifications are specific to the individual arrangement of the unit under consideration. It is recommended that a turbine manufacturer be contacted to determine the benefits and costs of making modifications to the runner seal design.

Discharge Ring Extension to Allow a Longer Runner Band (Francis Units)

Discharge ring modifications are specific to the individual arrangement of the unit under consideration. It is recommended that a turbine manufacturer be contacted to determine the benefits and costs of making modifications to the discharge ring to allow a longer runner.

Discharge Ring Diameter Increases with Increased Runner Diameters (Axial Flow Turbines)

Discharge ring modifications are specific to the individual arrangement of the unit under consideration. It is recommended that a turbine manufacturer be contacted to determine the benefits and costs of making modifications to the discharge ring to allow a runner with an increased diameter.

Nozzle Enlargements (Impulse Turbines)

Nozzle enlargements are specific to the individual arrangement of the unit under consideration. It is recommended that a turbine manufacturer be contacted to determine the benefits and costs of making modifications to nozzles.

Draft Tube Modifications

Draft tube modifications are specific to the individual arrangement of the unit under consideration and not included in the scope of this study. It is recommended that a turbine manufacturer be contacted to determine the benefits and costs of making modifications to the draft tube.

4.6.3 Generator/Generator-Motor Stator Rewind

The costs associated with generator modernization depend on many factors such as the design of the original generator, extent of the uprating, plant location relative to manufacturer's service shop, prospective contractor shop workloads, material costs (e.g., copper prices), and the extent of field work required. As a result, bid prices can vary by as much as 100% and only general cost guidelines can be presented here.

The cost of rewinding generators with new stator windings, including the labor to remove the old winding and install the new, can be determined from the following "rule of thumb":

- Machines up to 150 MW: $20,000–$50,000 per MW of nameplate rating
- Machines above 150 MW: $15,000–$30,000 per MW of nameplate rating

The above costs do not include site preparation that would involve unit isolation, removal of the rotor, erection of scaffolding and work platforms, and re-installation of the rotor. These costs are site specific and difficult to generalize.

4.6.4 Costs of Other Modifications of a Generator/Generator-Motor Modernization

As mentioned above, generator rewinds are many times accompanied by other component modifications to further enhance the upgrade of the unit. In most cases, costs of these modifications include both a supply and installation component.

Stator Core Restack

Generator modernization/rehabilitation may require stator core replacement based on the condition of stator core laminiations. Sample supply and installation costs taken from recent contracts provide the following cost ranges:

- $10,000–$30,000 per MVA namplate rating

As noted in Section 4.6.3, costs can vary widely based on a variety of factors. Equipment suppliers should be contacted for project-specific pricing.

Field Pole Winding Reinsulation

Generator modernization/rehabilitation may require generator field pole rehabilitation based on the condition of poles. Sample supply and installation costs taken from recent contracts provide the following cost ranges:

- Field pole refurbishment: $10,000–$40,000 per pole

Removal, shipping, and installation costs can vary widely based on a variety of factors. Equipment suppliers should be contacted for project-specific pricing.

4.6.5 Electrical/Mechanical Balance of Plant Systems, Governors and Controls

For a runner upgrade that results in an increase in unit capacity, it is important that other components also be assessed. This includes the generator, main power conductors, current breakers, and transformers. Equipment to consider is described in Volumes 3 (Electromechanical), 4 (Mechanical Auxiliaries) and 5 (Electrical Auxiliaries) of the EPRI guidelines. If upgrade or replacement of this equipment is necessary solely because of increased turbine output, the cost of upgrade/replacement should be included in the cost of runner upgrade.

4.7 Role of Permitting on Total Project Costs and Uncertainty

The non-federal hydropower industry is regulated by the Federal Energy Regulatory Commission (FERC or Commission) under authority granted by the Federal Power Act (FPA). Under the FPA, FERC has exclusive authority to license non-federal water power projects on navigable waterways and federal lands. The FPA was passed by Congress in 1920, with major amendments in 1986 and 2005. FERC issues original licenses, as well as new licenses (i.e., relicense existing facilities).

4.7.1 Applications for Original Licenses

Original licenses are currently restricted to newly constructed projects or existing projects that come under the Commission's jurisdiction. Original licenses are issued for a term up to 50 years. A license conveys the right of eminent domain.

A developer of a hydroelectric project must file a development application for an original license or exemption from licensing if the project is or will be:

§ Located on a navigable waterway of the U.S.;

§ Occupying U.S. lands;

§ Utilizing surplus water or water power from a U.S. government dam; or

§ Located on a body of water over which Congress has Commerce Clause jurisdiction, project construction occurred on or after August 26, 1935, and the project affects the interests of interstate or foreign commerce.

4.7.2 Applications for New Licenses (Relicenses)

Between 5 and 5½ years prior to a license's expiration date, the licensee must file a Notice of Intent (NOI) declaring whether or not it intends to seek a new license (relicense) for its project. At least 2 years before a license expires, the licensee must file an Application for New License. Projects undergoing relicensing make up the majority of the proposals being evaluated by the hydropower licensing staff of the Office of Energy Projects. The commission has three licensing processes, as described in Section 4.7.7.

4.7.3 Exemptions from Licensing

In certain cases, projects may qualify for an exemption from licensing. Those receiving an exemption are exempt from the requirements of Part I of the FPA. However, the exempted project is subject to mandatory terms and conditions set by federal and state fish and wildlife agencies and by the Commission, and do not convey the right of eminent domain. Obtaining an exemption can prove to be a more simplified process than applying for an original license; however, it requires three-stage consultation and the preparation of an application. Exemptions are issued in perpetuity.

The Commission issues two types of exemptions:

§ Small hydropower exemptions address projects that are 5 MW or less. In addition, such projects must be built at an existing dam or utilize a natural water feature for head. A small hydropower exemption may also be issued for an existing project that has a capacity of 5 MW or less and proposes to increase capacity.

§ Conduit exemptions address project that would be constructed on an existing conduit (for example irrigation canal). Conduit exemptions are authorized for generating capacities of 15 MW or less for non-municipal applicants and 40 MW or less for a municipal applicant. The conduit has to have been constructed primarily for purposes other than power production and be located entirely on non-federal lands.

4.7.4 Small/Low-Impact Hydropower Program

Consistent with the information provided above, under the Small/Low-Impact Hydropower Program, FERC issues three types of development authorizations: conduit exemptions, small hydropower 5 MW exemptions, and licenses. The Commission provides authorization to construct and operate small/low-impact projects while assuring adequate protection of environmental resources. The program is intended for small projects that would result in minor environmental effects (i.e., projects that involve little change to water flow and use and are unlikely to affect threatened and endangered species).

4.7.4.1 Conduit Exemptions

A conduit hydroelectric facility up to 15 MW (up to 40 MW for municipal projects) using a man-made conduit operated primarily for non-hydroelectric purposes may be eligible for a conduit exemption. The applicant must have all the real property interests necessary to develop and operate the project or an option to obtain the interests. The facility cannot occupy federal lands. The conduit on which the project is located is not included as a project work. Applications for exemptions of small hydroelectric conduits are categorically exempt from the requirement for an Environmental Assessment (EA) or Environmental Impact Statement (EIS) to be prepared by the Commission. However, this does not mean that the Commission cannot require an EA or EIS to be prepared if the project appears to have adverse effects on the environment.

4.7.4.2 Small Hydropower (≤5 MW Exemptions)

A small hydroelectric project of 5 MW or less may be eligible for a 5 MW exemption. In addition, for existing facilities, the applicant must propose to install or add capacity to a project located at a non-federal dam, or at a natural water feature. The project can be located on federal lands but cannot be located at a federal dam. The applicant must have all the real property interests or an option to obtain the interests in any non-federal lands.

4.7.5 Licenses

As discussed earlier, a license from the Commission is required to construct, operate, and maintain a non-federal hydroelectric project that is or would: (a) be located on navigable waters of the U.S.; (b) occupy U.S. lands; (c) utilize surplus water or water power from a U.S. government dam; or (d) be located on a stream over which Congress has Commerce Clause jurisdiction, where project construction or expansion occurred on or after August 26, 1935, and the project affects the interests of interstate or foreign commerce.

Licenses may be issued for up to 50 years terms and must be renewed at the end of each term. A license gives the licensee the power of eminent domain to obtain lands or other rights needed to construct, operate, and maintain the hydroelectric project.

Table 4-6 lists the differences among a conduit exemption, 5 MW exemption, and a license. Using this information can help determine which exemption or license process best suits a specific project.

Table 4-6
Project Comparison Chart

	Conduit Exemption	5 MW Exemption	License
Installed Capacity Limitations	· 15 MW or less (for non-municipality) · 40 MW or less (for a municipality)	· 5 MW or less	· Unlimited
Location Limitations in Addition to Off-Limits Sites	· Must be located on a conduit used for agricultural, municipal, or industrial consumption · Cannot be located on federal lands · Cannot be located at an impoundment	· Must be located at an existing dam or natural water feature · Cannot be located at a dam owned or operated by the federal government	
Ownership Limitations	· Must have all real property rights necessary to develop and operate the project or an option to obtain such interests · Proof of ownership required at time of filing the application	· If located on private lands, must have all real property rights necessary to develop and operate the project or an option to obtain such interests · Proof of ownership required at time of filing the application	· Proof of ownership not required at time of filing the application; power of eminent domain may be conferred by section 21 of the FPA, 16 U.S.C. § 814
Term Limitations	· Issued in perpetuity	· Issued in perpetuity	· Up to 50 years for license
May be Subject to the Following Mandatory Conditions	· Federal and state fish and wildlife conditions under section 30(c) of the FPA, 16 U.S.C. § 823a(c)	· Federal and state fish and wildlife conditions under section 30(c) of the FPA, 16 U.S.C. § 823a(c)	· Federal reservation conditions under section 4(e) of the FPA, 16 U.S.C. § 797(e) · Fishway prescriptions under section 18 of the FPA, 16 U.S.C. § 811
Consultation Requirements	· 3-stage consultation required under 18 C.F.R. § 4.38 · With concurrence from all resource agencies, the applicant may seek waiver of the consultation requirements under 18 C.F.R. § 4.38(e)	· 3-stage consultation required under 18 C.F.R. § 4.38 · With concurrence from all resource agencies, the applicant may seek waiver of the consultation requirements under 18 C.F.R. § 4.38(e)	· Integrated Licensing Process (ILP) required under 18 C.F.R § 5 · If waiver of ILP regulations was sought under 18 C.F.R. § 5.1(f), and granted, then 3-stage consultation required under 18 C.F.R. § 4.34(i) for the Alternative Licensing Process or 18 C.F.R. § 4.38 for the Traditional Licensing Process · With concurrence from all resource agencies, the applicant may seek waiver of the consultation require-ments under 18 C.F.R. § 4.38(e)

Table 4-6 (continued)
Project Comparison Chart

	Conduit Exemption	5 MW Exemption	License
Preparation of Environmental Document	· Categorically exempt from preparing an environmental document under 18 C.F.R. § 380.4(a)(14) unless determined necessary	· Prepared consistent with NEPA	· Prepared consistent with NEPA
Project Boundary	· Includes powerhouse and connection to conduit (excludes the transmission line and the conduit itself).	· Includes all associated lands and facilities, such as the powerhouse, dam, impoundment, transmission line, and any lands that fulfill a project purpose (*e.g.*, recreation, resource protection, and access roads).	· Includes all associated lands and facilities, such as the powerhouse, dam, impoundment, transmission line, and any lands that fulfill a project purpose (*e.g.*, recreation, resource protection, and access roads).
Filing Fees	· None	· None	· None
Annual Charges	· Currently projects up to 1.5 MW not charged	· Currently projects up to 1.5 MW not charged	· Currently projects up to 1.5 MW not charged
Implementing Statutes	· FPA section 30(c). 16 U.S.C. § 823a	· Public Utility Regulatory Policies Act (PURPA) sections 405 and 408. · 16 U.S.C. §§ 2705 and 2708	· FPA sections 4 thru 27 16 U.S.C. §§ 797-821
Application Regulations	· 18 C.F.R. §§ 4.90-4.96	· 18 C.F.R. §§ 4.101-4.108	· 18 C.F.R. § 5 (Integrated Licensing Process) · 18 C.F.R. §§ 4.30-4.61(Traditional Licensing Process) · 18 C.F.R. § 4.34(i) (Alternative Licensing Process)

4.7.6 Statutes Affecting Project Licensing

In addition to the FPA, there are several statues that affect the licensing process.

4.7.6.1 Major Statutes Affecting Hydropower Licensing

National Environmental Policy Act - Requires FERC to prepare an environmental report, in coordination with other agencies, about the environmental impacts of licensing a project and alternatives to the project, and to consider impacts and alternatives when making licensing and exemption decisions.

Endangered Species Act - Requires FERC to consult with United State Fish and Wildlife Service (USFWS) and/or National Oceanic and Atmospheric Administration (NOAA)-Fisheries before issuing a license or exemption to ensure that the action is not likely to jeopardize the continued existence of a listed species or critical habitat.

Clean Water Act - Requires that a project obtain a water quality certificate from the state in which a "discharge" occurs, and allows the state to condition the license related to water quality and other relevant provisions of state law.

National Historic Preservation Act (Section 106) - Requires FERC to consider the effects of licensing or exempting a project on historic properties.

4.7.6.2 Secondary Statutes Affecting Licensing

Fish and Wildlife Coordination Act - Requires FERC to consult with USFWS, NOAA-Fisheries, and state fish and wildlife agencies before issuing license or exemption and to fully consider the recommendations of these agencies.

Bald and Golden Eagle Protection Act - Provides for the protection of bald and golden eagles regardless of federal or state status.

Migratory Bird Treaty Act - Promotes conservation of migratory birds and associated habitat. Emphasized by the March 2011 Memorandum of Understanding between FERC and the USFWS.

Coastal Zone Management Act - Approval of state Coastal Zone Management Program required for all projects within or that would influence the coastal zone.

Magnuson-Stevens Fishery Conservation and Management Act - Gives NOAA-Fisheries authority over all anadromous fish throughout their migratory ranges, and establishes the criteria for performing essential fish habitat (EFH) assessments.

4.7.7 Filing a Hydropower License Application with the Commission

Effective July 23, 2005, the Integrated Licensing Process (ILP) is the default process for filing an application for an original, new, or subsequent license. Commission approval is needed to use either the Traditional Licensing Process (TLP) or the Alternative Licensing Process (ALP). Summaries of these three processes are given in the following sections.

4.7.7.1 Integrated Licensing Process

The ILP is a more formal and front-loaded process compared to the other two licensing processes, which is intended to reduce the level of effort associated with post-application filing activities and reduce the potential for an extended consultation process in the latter stages of the licensing process. Figure 4-11 presents a flow chart of the ILP from the FERC website.

Timeline for the Integrated Licensing Process

The timeline for the ILP is 3½ to 4½ years, depending on the extent of the studies and application development.

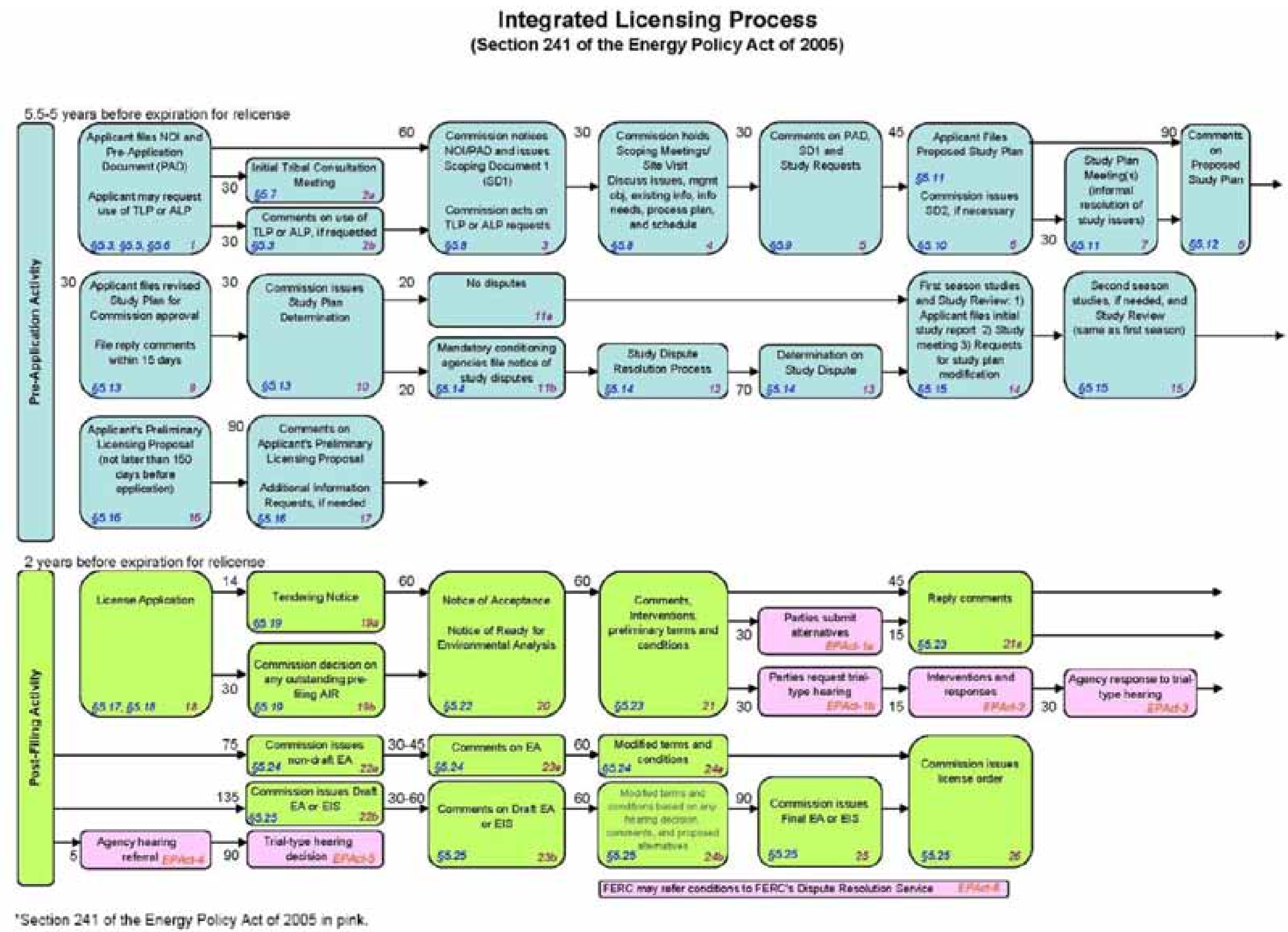

Figure 4-11
Integrated Licensing Process

4.7.7.2 Traditional Licensing Process

In developing a TLP license application, applicants must complete and document a three-stage pre-filing consultation process for original licenses and for relicenses. The steps include:

First Stage

§ Applicant issues notice of intent, preliminary application document, request to use TLP, and newspaper notice;

§ Commission approves use of TLP;

§ Applicant conducts joint agency/public meeting and site visit;

§ Resource agencies and tribes provide written comments; and

§ Agencies, tribes, or applicant request dispute resolution on studies with the Commission.

Second Stage

§ Applicant completes reasonable and necessary studies o Applicant provides draft application and study results to resource agencies and tribes;

§ Resource agencies and tribes comment on draft application; and

§ Applicant conducts meeting if substantive disagreements exist.

Third Stage

§ Applicant files final application with Commission and sends copies to agencies and tribes.

FERC must approve the use of the TLP and has six criteria for use of this process, as follows:

§ Likelihood of timely license issuance;

§ Complexity of the resource issue;

§ Level of anticipated controversy;

§ Cost of the TLP relative to the ILP;

§ The amount of available information and potential for significant disputes over studies; and

§ Other factors believed to be pertinent.

The process to request use of the TLP is as follows:

§ Must file request to use the TLP (or ALP);

§ Request is filed in conjunction with Pre-Applicatino Document (PAD) and NOI;

§ Supported by initial consultation activities (PAD questionnaire);

- Must file and address comments related to consultation;
- Requires 30-day public notice period; and
- FERC acts on TLP request within 60 days of filing.

Timeline for the Traditional Licensing Process

The TLP has response timelines but is not as formal as the ILP and can therefore continue for several years.

4.7.7.3 Alternative Licensing Process

In contrast to the TLP, Applicants can utilize the Commission's ALP, which is designed to improve communication among affected entities. As part of the ALP, an applicant can:

- Tailor the pre-filing consultation process to the circumstances of each case;
- Combine into a single process the pre-filing consultation process and environmental review processes under the National Environmental Policy Act (NEPA)and other statutes; and
- Allow for preparation of a preliminary draft environmental assessment by an applicant or an environmental impact statement by a contractor chosen by the Commission and funded by the applicant.

The ALP was the second process developed by FERC, following the TLP, and incorporated FERC NEPA analyses into the Stage I and II activities. Other aspects of the ALP are:

- Involves comprehensive collaborative process with the potential for extensive number of meetings;
- Potential benefits of ALP NEPA analysis have been incorporated into the ILP;
- Does not establish criteria for post-filing additional information requests;
- Potential that ALP can prove too labor and resource intensive with limited benefits; and
- Usually not recommended unless rather special circumstances.

4.7.8 Amendments to Project License

Typical modifications that require an amendment to a license or exemption include changes in capacity, project design, operations, and land status, as well as time extensions associated with performing activities required by the license or exemption. FERC issues two general types of amendments: capacity amendments and non-capacity amendments.

4.7.8.1 Capacity Amendment

The Commission defines a modification that requires a capacity amendment as one that would: (1) increase the project's actual or proposed total installed capacity, increase the project maximum hydraulic capacity by 15% or more, and increase the project nameplate capacity by 2 MW or more; or (2) entail significant construction or modifications as specified at 18 CFR 4.38(a)(4)(v). Capacity amendments are subject to the three-stage consultation requirements, similar to the TLP.

4.7.8.2 Non-capacity Amendment

A project modification that does not exceed the thresholds associated with a capacity amendment is considered a modification that requires a non-capacity amendment. Non-capacity amendments are not subject to the three-stage consultation requirements that apply to capacity amendments.

4.7.8.3 Amendments for Efficiency Upgrades

FERC reviews proposed modifications to hydropower projects that would allow the project to produce energy more efficiently. Reviews are completed through the Efficiency Upgrade Program, which was designed to encourage the hydropower industry to evaluate options for increasing efficiency. To help meet this objective, FERC assists licensees who want to improve their project efficiency. Methods with the greatest potential for increasing efficiency include:

§ Upgrading generators/turbines;

§ Adding units;

§ Computerizing project controls;

§ Optimizing flow regulation;

§ Increasing upstream/downstream plant coordination;

§ Reducing excess spill volumes; and

§ Raising the level of a project's reservoir.

Although the thresholds for requiring a capacity amendment may be exceeded, efficiency upgrades at hydropower projects typically qualify for a non-capacity amendment. An typical exception to this statement is when the modification includes the addition of additional units.

4.7.9 Licensing Costs

The licensing costs of 47 projects using all three licensing process were evaluates. Ten projects were licensed by the ILP, 18 projects were licensed by the TLP, and 19 projects were licensed by the ALP.

Figure 4-12 shows the relicensing cost for the 47 projects by dollars per MW ($/MW) in 2010 dollars. The curve represents the equation $/MW = 543,490

$MW^{-0.404}$ for the cost of the relicensing. These estimates are applicable for exiting projects, upgrades, and powering non-power dams, but may not be applicable for greenfield projects as many of the project issues may be unknown.

The cost information indicates the larger the authorized capacity of the project the cost of licensing per megawatt decreases which can be contributed to fixed costs being distributed over a larger capacity. Variability in this general trend exists, as shown in the figure, and is likely due to the specific aspects associated with the licensing effort. An evaluation of the site-specific issues and requirements would be necessary to further define the common factors that influence total relicensing costs.

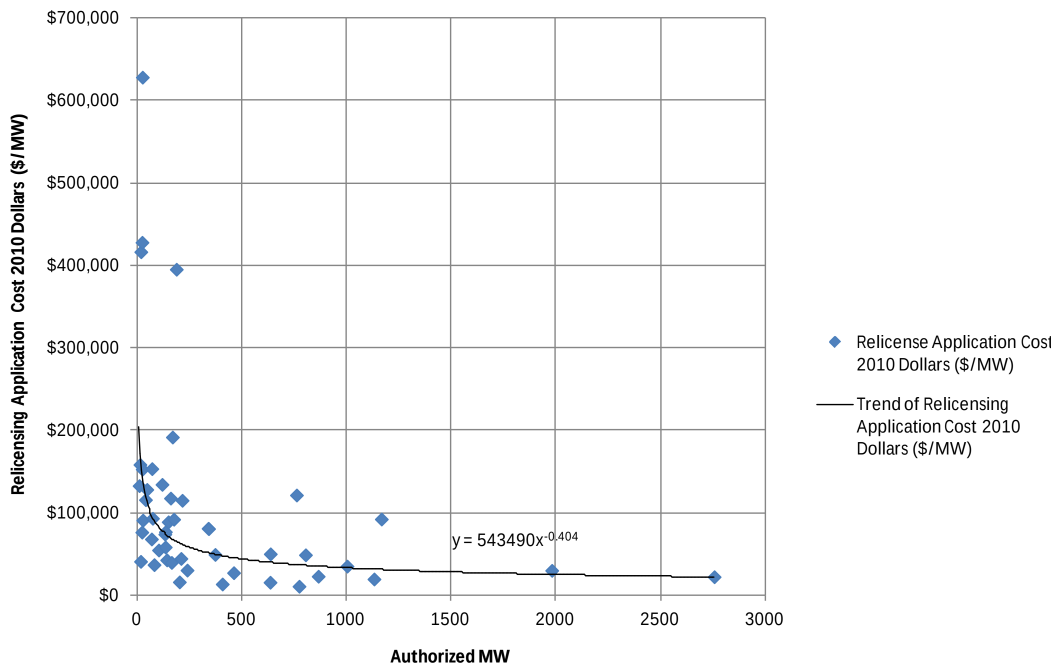

Figure 4-12
Relicense Application Cost 2010 Dollars ($/MW)

Section 5: References

EPRI. 1990. Pumped-Storage Planning and Evaluation Guide, EPRI GS-6669, January 1990.

EPRI. 1995. Application of Adjustable Speed Machines in Conventional Pumps Storage Hydro Projects, EPRI TR-105542, November 1995.

EPRI. 1999a. Hydro Life Extension Modernization Guides: Volume 1, Overall Process, EPRI, Palo Alto, CA: 1999. TR-112350-V1.

EPRI. 1999b. Rehabilitation and Upgrading Hydro Plants: A Hydropower Technology Round-Up Report, Volume 2, EPRI, Palo Alto, CA: 1999. TR-113584-V2.

EPRI. 2000a. Hydro Life Extension Modernization Guides: Volume 2, Hydromechanical Equipment, EPRI, Palo Alto, CA: 2000. TR-112350-V2.

EPRI. 2000b. Hydro Life Extension Modernization Guide: Volume 7, Protection and Control, EPRI, Palo Alto, CA: 2000. TR-112350-V7.

EPRI. 2001a. Hydro Life Extension Modernization Guide, Volume 3, Electromechanical Equipment, EPRI, Palo Alto, CA: 2001. TR-112350-V3.

EPRI. 2001b. Hydro Life Extension Modernization Guides: Volume 4-5, Auxiliary Mechanical and Electrical Systems, EPRI, Palo Alto, CA: 2001. TR-112350V4.

INEL. 2003. Estimation of Economic Parameters of U.S. Hydropower Resources, INEL/EXT-03-00662, June 2003.

Tudor Engineering Company. 1980. Reconnaissance Evalulation of Small, Low-Head Hydroelectric Installations, Report to Water and Power Resources Service, U.S. Department of Interior, July 1980.

U.S. Army Corps of Engineers. 2010. Civil Works Construction Cost Index System (CWCCIS), September 30, 2010.

U.S. Bureau of Reclamation. Construction Cost Trends.

Appendix A: Cost Index Tables

Table A-1
EPRI Cost Escalation Factors – Pumped Storage Hydropower Projects

	USACE Civil Works Historical Construction Cost Indices (Power Plant)			RS Means Historical Cost Indices			Bureau of Rec Historical Construction Cost Indices (Composite)			Bureau of Rec Historical Construction Cost Indices (Equipment)			Engineering New Record Historical Construction Indices			Average	
Year	Index Value [1]	Ann. % Incr.	Cum. % Incr.	Index Value[2]	Ann. % Incr.	Cum. % Incr.	Index Value [2]	Ann. % Incr.	Cum % Incr.	Index Value[2]	Ann % Incr.	Cum % Incr.	Index Value	Ann. % Incr.	Cum. % Incr.	Ann. % Incr.	Cum. % Incr.
1988	355.4			89.9			168			179			4519.4				
1989	370.6	4.3%	4.3%	92.1	2.4%	2.4%	174	3.6%	3.6%	190	6.1%	6.1%	4615.0	2.1%	2.1%	3.7%	3.7%
1990	382.7	3.3%	7.7%	94.3	2.4%	4.9%	179	2.9%	6.5%	199	4.7%	11.2%	4731.9	2.5%	4.7%	3.2%	7.0%
1991	396.0	3.5%	11.4%	96.8	2.7%	7.7%	184	2.8%	9.5%	209	5.0%	16.8%	4835.2	2.2%	7.0%	3.2%	10.5%
1992	403.4	1.9%	13.5%	99.4	2.7%	10.6%	186	1.1%	10.7%	215	2.9%	20.1%	4984.8	3.1%	10.3%	2.3%	13.0%
1993	411.8	2.1%	15.8%	101.7	2.3%	13.1%	190	2.2%	13.1%	220	2.3%	22.9%	5210.4	4.5%	15.3%	2.7%	16.1%
1994	422.2	2.5%	18.8%	104.4	2.7%	16.1%	197	3.7%	17.3%	223	1.4%	24.6%	5407.6	3.8%	19.7%	2.8%	19.3%
1995	432.8	2.5%	21.8%	107.6	3.1%	19.7%	206	4.6%	22.6%	228	2.2%	27.4%	5471.2	1.2%	21.1%	2.7%	22.5%
1996	441.9	2.1%	24.3%	110.2	2.4%	22.6%	209	1.5%	24.4%	227	-0.4%	26.8%	5622.2	2.8%	24.4%	1.7%	24.5%
1997	447.1	1.2%	25.8%	112.8	2.4%	25.5%	218	4.3%	29.8%	231	1.8%	29.1%	5825.1	3.6%	28.9%	2.6%	27.8%
1998	457.1	2.2%	28.6%	115.1	2.0%	28.0%	219	0.5%	30.4%	235	1.7%	31.3%	5920.4	1.6%	31.0%	1.6%	29.9%
1999	461.4	1.0%	29.8%	117.6	2.2%	30.8%	225	2.7%	33.9%	239	1.7%	33.5%	6060.0	2.4%	34.1%	2.0%	32.4%
2000	469.5	1.8%	32.1%	120.9	2.8%	34.5%	231	2.7%	37.5%	242	1.3%	35.2%	6221.2	2.7%	37.7%	2.2%	35.4%
2001	476.7	1.5%	34.1%	125.1	3.5%	39.2%	235	1.7%	39.9%	247	2.1%	38.0%	6334.0	1.8%	40.2%	2.1%	38.3%
2002	483.8	1.5%	36.1%	128.7	2.9%	43.2%	240	2.1%	42.9%	254	2.8%	41.9%	6537.9	3.2%	44.7%	2.5%	41.7%
2003	494.6	2.2%	39.2%	132.0	2.6%	46.8%	248	3.3%	47.6%	258	1.6%	44.1%	6694.7	2.4%	48.1%	2.4%	45.2%
2004	508.3	2.8%	43.0%	143.7	8.9%	59.8%	265	6.9%	57.7%	265	2.7%	48.0%	7114.9	6.3%	57.4%	5.5%	53.2%
2005	550.6	8.3%	54.9%	151.6	5.5%	68.6%	283	6.8%	68.5%	274	3.4%	53.1%	7446.0	4.7%	64.8%	5.7%	62.0%
2006	578.0	5.0%	62.6%	162.0	6.9%	80.2%	301	6.4%	79.2%	285	4.0%	59.2%	7887.6	5.9%	74.5%	5.6%	71.1%

Table A-1 (continued)
EPRI Cost Escalation Factors – Pumped Storage Hydropower Projects

	USACE Civil Works Historical Construction Cost Indices (Power Plant)			RS Means Historical Cost Indices			Bureau of Rec Historical Construction Cost Indices (Composite)			Bureau of Rec Historical Construction Cost Indices (Equipment)			Engineering New Record Historical Construction Indices			Average	
Year	**Index Value [1]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value[2]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value [2]**	**Ann. % Incr.**	**Cum % Incr.**	**Index Value[2]**	**Ann % Incr.**	**Cum % Incr.**	**Index Value**	**Ann. % Incr.**	**Cum. % Incr.**	**Ann. % Incr.**	**Cum. % Incr.**
2007	605.9	4.8%	70.5%	169.4	4.6%	88.4%	314	4.3%	86.9%	300	5.3%	67.6%	8551.3	8.4%	89.2%	5.5%	80.5%
2008	635.0	4.8%	78.7%	180.4	6.5%	100.7%	340	8.3%	102.4%	316	5.3%	76.5%	8549.1	0.0%	89.2%	5.0%	89.5%
2009	660.7	4.0%	85.9%	180.1	-0.2%	100.3%	327	-3.8%	94.6%	326	3.2%	82.1%	8660.1	1.3%	91.6%	0.9%	90.9%
2010	670.5	1.5%	**88.6%**	183.5	1.9%	**104.1%**	340	4.0%	**102.4%**	334	2.5%	**86.6%**	8952.4	3.4%	**98.1%**	2.6%	**96.0%**
1988 to 2010 dollar conversion factors																	
USACE	1.9																
RS Means	2.0																
Bureau of Rec	2.0																
ENR	2.0																

Table A-2
EPRI Cost Escalation Factors – Conventional Hydropower Projects

	USACE Civil Works Historical Construction Cost Indices (Power Plant)			RS Means Historical Cost Indices			Bureau of Rec Historical Construction Cost Indices (Composite)			Engineering New Record Historical Construction Indices			Average	
Year	**Index Value [1]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value[2]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value[2]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value**	**Ann. % Incr.**	**Cum. % Incr.**	**Ann. % Incr.**	**Cum. % Incr.**
1978 [3]	214.4			53.5		0.0%	106			2776.0				
1979 [3]	233.5	8.9%	8.9%	57.8	8.0%	8.0%	117	10.4%	10.4%	3002.6	8.2%	8.2%	8.9%	8.9%
1980	254.9	9.2%	18.9%	62.9	8.8%	17.6%	130	11.1%	22.6%	3237.1	7.8%	16.6%	9.2%	18.9%
1981	282.5	10.8%	31.8%	70.0	11.3%	30.8%	142	9.2%	34.0%	3534.9	9.2%	27.3%	10.1%	31.0%
1982	309.8	9.7%	44.5%	76.1	8.7%	42.2%	150	5.6%	41.5%	3825.1	8.2%	37.8%	8.1%	41.5%
1983	319.8	3.2%	49.1%	80.2	5.4%	49.9%	152	1.3%	43.4%	4066.3	6.3%	46.5%	4.1%	47.2%
1984	329.2	3.0%	53.6%	82.0	2.2%	53.3%	154	1.3%	45.3%	4145.7	2.0%	49.3%	2.1%	50.4%
1985	335.6	1.9%	56.5%	82.6	0.7%	54.4%	157	1.9%	48.1%	4195.0	1.2%	51.1%	1.4%	52.5%
1986	339.4	1.2%	58.3%	84.2	1.9%	57.4%	159	1.3%	50.0%	4295.0	2.4%	54.7%	1.7%	55.1%
1987	344.8	1.6%	60.8%	87.7	4.2%	63.9%	161	1.3%	51.9%	4406.4	2.6%	58.7%	2.4%	58.8%
1988	355.4	3.1%	65.8%	89.9	2.5%	68.0%	166	3.1%	56.6%	4519.4	2.6%	62.8%	2.8%	63.3%
1989	370.6	4.3%	72.8%	92.1	2.4%	72.1%	174	4.8%	64.2%	4615.0	2.1%	66.2%	3.4%	68.8%
1990	382.7	3.3%	78.5%	94.3	2.4%	76.3%	179	2.9%	68.9%	4731.9	2.5%	70.5%	2.8%	73.5%
1991	396.0	3.5%	84.7%	96.8	2.7%	80.9%	184	2.8%	73.6%	4835.2	2.2%	74.2%	2.8%	78.3%
1992	403.4	1.9%	88.1%	99.4	2.7%	85.8%	186	1.1%	75.5%	4984.8	3.1%	79.6%	2.2%	82.2%
1993	411.8	2.1%	92.0%	101.7	2.3%	90.1%	190	2.2%	79.2%	5210.4	4.5%	87.7%	2.8%	87.3%
1994	422.2	2.5%	96.9%	104.4	2.7%	95.1%	197	3.7%	85.8%	5407.6	3.8%	94.8%	3.2%	93.2%
1995	432.8	2.5%	101.9%	107.6	3.1%	101.1%	206	4.6%	94.3%	5471.2	1.2%	97.1%	2.8%	98.6%
1996	441.9	2.1%	106.1%	110.2	2.4%	106.0%	209	1.5%	97.2%	5622.2	2.8%	102.5%	2.2%	102.9%
1997	447.1	1.2%	108.5%	112.8	2.4%	110.8%	218	4.3%	105.7%	5825.1	3.6%	109.8%	2.9%	108.7%
1998	457.1	2.2%	113.2%	115.1	2.0%	115.1%	219	0.5%	106.6%	5920.4	1.6%	113.3%	1.6%	112.0%
1999	461.4	1.0%	115.2%	117.6	2.2%	119.8%	225	2.7%	112.3%	6060.0	2.4%	118.3%	2.1%	116.4%
2000	469.5	1.8%	119.0%	120.9	2.8%	126.0%	231	2.7%	117.9%	6221.2	2.7%	124.1%	2.5%	121.7%
2001	476.7	1.5%	122.3%	125.1	3.5%	133.8%	235	1.7%	121.7%	6334.0	1.8%	128.2%	2.1%	126.5%
2002	483.8	1.5%	125.6%	128.7	2.9%	140.6%	240	2.1%	126.4%	6537.9	3.2%	135.5%	2.4%	132.0%

... A-4 †

Table A-2 (continued)
EPRI Cost Escalation Factors – Conventional Hydropower Projects

	USACE Civil Works Historical Construction Cost Indices (Power Plant)			RS Means Historical Cost Indices			Bureau of Rec Historical Construction Cost Indices (Composite)			Engineering New Record Historical Construction Indices			Average	
Year	**Index Value [1]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value[2]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value[2]**	**Ann. % Incr.**	**Cum. % Incr.**	**Index Value**	**Ann. % Incr.**	**Cum. % Incr.**	**Ann. % Incr.**	**Cum. % Incr.**
2003	494.6	2.2%	130.7%	132.0	2.6%	146.7%	248	3.3%	134.0%	6694.7	2.4%	141.2%	2.6%	138.1%
2004	508.3	2.8%	137.1%	143.7	8.9%	168.6%	265	6.9%	150.0%	7114.9	6.3%	156.3%	6.2%	153.0%
2005	550.6	8.3%	156.8%	151.6	5.5%	183.4%	283	6.8%	167.0%	7446.0	4.7%	168.2%	6.3%	168.8%
2006	578.0	5.0%	169.6%	162.0	6.9%	202.8%	301	6.4%	184.0%	7887.6	5.9%	184.1%	6.0%	185.1%
2007	605.9	4.8%	182.6%	169.4	4.6%	216.6%	314	4.3%	196.2%	8551.3	8.4%	208.0%	5.5%	200.9%
2008	635.0	4.8%	196.2%	180.4	6.5%	237.2%	340	8.3%	220.8%	8549.1	0.0%	208.0%	4.9%	215.5%
2009	660.7	4.0%	208.2%	180.1	-0.2%	236.6%	327	-3.8%	208.5%	8660.1	1.3%	212.0%	0.3%	216.3%
2010	670.5	1.5%	**212.7%**	183.5	1.9%	**243.0%**	340	4.0%	**220.8%**	8952.4	3.4%	**222.5%**	2.7%	**224.7%**
1978 to 2010 dollar conversion factors														
USACE		3.1												
RS Means		3.4												
Bureau of Rec		3.2												
ENR		3.2												
Average		3.2												

Appendix B: AACE Class 1 Through 5 Cost Estimate Classifications

Table B-1
AACE Class 1 Through 5 Cost Estimate Classifications

Estimate Class	Class 5		Class 4		Class 3		Class 2		Class 1	
LEVEL OF PROJECT DEFINITION Expressed as a % of complete definition	0% to 2%		1% to 15%		10% to 40%		30% to 70%		50% to 100%	
END USAGE Typical purpose of estimate	Concept Screening		Study or Feasibility		Budget Authorization or Control		Control or Bid / Tender		Check Estimate or Bid / Tender	
METHODOLOGY Typical estimating method	Capacity Factored, Parametric Models, Judgment, or Analogy		Equipment Factored or Parametric Models		Semi-Detailed Unit Costs with Assembly Level Line Items		Detailed Unit Cost with Forced Detailed Take-Off		Detailed Unit Cost with Detailed Take-Off	
EXPECTED ACCURACY RANGE Typical variation in low and high ranges (a)	L: -20% to -50%	H: +30% to +100%	L: -15% to -30%	H: +20% to +50%	L: -10% to -20%	H: +10% to +30%	L: -5% to -15%	H: +5% to +20%	L: -3% to -10%	H: +3% to +15%
PREPARATION EFFORT Typical degree of effort relative to least cost index of 1 (b)	1		2 to 4		3 to 10		4 to 20		5 to 100	

Table B-2 (continued)
AACE Class 1 Through 5 Cost Estimate Classifications

Estimate Class	Class 5	Class 4	Class 3	Class 2	Class 1
REFINED CLASS DEFNITION	Class 5 estimates are generally prepared based on very limited information, and subsequently have wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systemic manner. Class 5 estimates, due to the requirements of end use, may be prepared within a very limited amount of time and with little effort expended—sometimes requiring less than 1 hour to prepare. Often, little more than proposed plant type, location, and capacity are known at the time of estimate preparation.	Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists.	Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists.	Class 2 estimates are generally prepared to form a detailed control baseline against which all project work is monitored in terms of cost and progress control. For contractors, this class of estimate is often used as the “bid” estimate to establish contract value. Typically, engineering is from 30% to 70% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, piping and instrument diagrams, heat and material balances, final plot plan, final layout drawings, complete engineered process and utility equipment lists, single line diagrams for electrical, electrical equipment and motor schedules, vendor quotations, detailed project execution plans, resourcing and work force plans, etc.	Class 1 estimates are generally prepared for discrete parts or sections of the total project rather than generating this level of detail for the entire project. The parts of the project estimated at this level of detail will typically be used by subcontractors for bids, or by owners for check estimates. The updated estimate is often referred to as the current control estimate and becomes the new baseline for cost/schedule control of the project. Class 1 estimates may be prepared for parts of the project to comprise a fair price estimate or bid check estimate to compare against a contractor’s bid estimate, or to evaluate/dispute claims. Typically, engineering is from 50% to 100% complete, and would comprise virtually all engineering and design documentation of the project, and complete project execution and commissioning plans.

Table B-2 (continued)
AACE Class 1 Through 5 Cost Estimate Classifications

Estimate Class	Class 5	Class 4	Class 3	Class 2	Class 1
END USAGE DEFINED	Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long-range capital planning, etc.	Class 4 estimates are prepared for a number of purposes, such as but not limited to detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.	Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase “control estimates” against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate may be the last estimate required and could well form the only basis for cost/schedule control.	Class 2 estimates are typically prepared as the detailed control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program.	Class 1 estimates are typically prepared to form a current control estimate to be used as the final control baseline against which all actual costs and resources will now be monitored for variations to the budget, and form a part of the change/variation control program. They may be used to evaluate bid checking, to support vendor/contractor negotiations, or for claim evaluations and dispute resolution.
ESTIMATING METHODS USED	Class 5 estimates virtually always use stochastic estimating methods such as cost/capacity curves and factors, scale of operations factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, and other parametric and modeling techniques.	Class 4 estimates virtually always use stochastic estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques.	Class 3 estimates usually involve more deterministic estimating methods than stochastic methods. They usually involve a high degree of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring and other stochastic methods may be used to estimate less-significant areas of the project.	Class 2 estimates always involve a high degree of deterministic estimating methods. Class 2 estimates are prepared in great detail, and often involve tens of thousands of unit cost line items. For those areas of the project still undefined, an assumed level of detail takeoff (forced detail) may be developed to use as line items in the estimate instead of relying on factoring methods.	Class 1 estimates involve the highest degree of deterministic estimating methods, and require a great amount of effort. Class 1 estimates are prepared in great detail, and thus are usually performed on only the most important or critical areas of the project. All items in the estimate are usually unit cost line items based on actual design quantities.

Table B-2 (continued)
AACE Class 1 Through 5 Cost Estimate Classifications

Estimate Class	Class 5	Class 4	Class 3	Class 2	Class 1
EXPECTED ACCURACY RANGE	Typical accuracy ranges for Class 5 estimates are -20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 2 estimates are -5% to -15% on the low side, and +5% to +20% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.	Typical accuracy ranges for Class 1 estimates are -3% to -10% on the low side, and +3% to +15% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Ranges could exceed those shown in unusual circumstances.
EFFORT TO PREPARE (for US$20MM project)	As little as 1 hour or less to perhaps more than 200 hours, depending on the project and the estimating methodology used.	Typically, as little as 20 hours or less to perhaps more than 300 hours, depending on the project and the estimating methodology used.	Typically, as little as 150 hours or less to perhaps more than 1,500 hours, depending on the project and the estimating methodology used.	Typically, as little as 300 hours or less to perhaps more than 3,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.	Class 1 estimates require the most effort to create, and as such are generally developed for only selected areas of the project, or for bidding purposes. A complete Class 1 estimate may involve as little as 600 hours or less, to perhaps more than 6,000 hours, depending on the project and the estimating methodology used. Bid estimates typically require more effort than estimates used for funding or control purposes.

Table B-2 (continued)
AACE Class 1 Through 5 Cost Estimate Classifications

Estimate Class	Class 5	Class 4	Class 3	Class 2	Class 1
ANSI Standard Reference Z94.2-1969 name; Alternate Estimate Names, Terms, Expressions, Synonyms	Order of magnitude estimate, ratio, ballpark, blue sky, seat-of-pants, ROM, idea study, prospect estimate, concession license estimate, guesstimate, rule-of-thumb.	Budget estimate, screening, top-down, feasibility, authorization, factored, pre-design, pre-study.	Budget estimate, budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, development, basic engineering phase estimate, target estimate.	Definitive estimate, detailed control, forced detail, execution phase, master control, engineering, bid, tender, change order estimate.	Definitive estimate, full detail, release, fall-out, tender, firm price, bottoms-up, final, detailed control, forced detail, execution phase, master control, fair price, definitive, change order estimate.

Notes:

(a) The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

(b) If the range index value of “1” represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

Source: AACE International Recommended Practice No. 18R-197, February 2, 2005.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute Inc., (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together...Shaping the Future of Electricity

Programs:

Waterpower

Bulk Power System Integration of Variable Generation

1023140

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com