Hydropower Technology Roundup Report: Accommodating Wear and Tear Effects on Hydroelectric Facilities Operating to Provide Ancillary Services

TR-113584-V4

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Technical Report

Hydropower Technology Roundup Report: Accommodating Wear and Tear Effects on Hydroelectric Facilities Operating to Provide Ancillary Services

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1004047

Final Report, August 2001

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This report was prepared by

HCI Publications
410 Archibald Street
Kansas City, MO 64111

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This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Hydropower Technology Roundup Report: Accommodating Wear and Tear Effects on Hydroelectric Facilities Operating to Provide Ancillary Services: TR-113584-V4, EPRI, Palo Alto, CA: 2001. 1004047.

REPORT SUMMARY

Ancillary services are special generation services necessary to maintain both power quality and system integrity. This report aims to provide useful information on accommodating wear and tear of hydropower units when operated to produce ancillary services. The information contained in this report can help hydro plant owners and operators:

- Better understand wear and tear effects
- Devise strategies to mitigate these effects
- Determine the costs associated with wear and tear

This information should help in the pricing of and recovering costs for ancillary service commitments. In addition, this report complements other work sponsored by EPRI on multiproject optimization (within its Hydro Asset Management [85.3] research activity). Finally, this report identifies areas where additional research is needed.

Background
Dramatic changes in the marketplace for electricity are making the supply of ancillary services an attractive market for hydro plants. However, providing ancillary services often can result in increased rates of unit wear and tear. To meet the requirements of the rapidly evolving marketplace, hydro project managers need to understand both wear and tear effects and the associated costs.

Objectives
- To review ancillary services ideally provided by hydro units and the impacts on hydro components
- To examine methodologies for estimating wear and tear and develop examples of their calculation
- To identify strategies for practical assessment and accommodation of wear and tear effects
- To look at areas that hold promise for future research

Approach
The investigators identified and reviewed pertinent literature and consulted with researchers and knowledgeable industry personnel.

Results
This report summarizes the information developed and provides a starting point for analyzing specific projects or systems. The report describes ancillary services in markets that currently

exist or have yet to be developed. In addition, the report provides a framework for assessing wear and tear liabilities and guidance on estimating wear-and-tear-related costs.

EPRI Perspective

Faced with a rapidly changing industry structure (including competition), hydropower project owners and operators need up-to-date information about the options available for meeting a diverse set of new challenges. They need information about the benefits and costs of alternative technologies and strategies. They need to know what works, or is likely to work, and what does not. EPRI's Hydropower Technology Roundup Report series provides a clearinghouse of information from worldwide sources on key topics, including new and emerging technologies and approaches. This report on accommodating wear and tear is the fourth in the Hydropower Technology Roundup Report series, published periodically since 1999.

Keywords

Ancillary services
Hydroelectric
Reactive power
Regulation
Reserves
Wear and tear

ACKNOWLEDGMENTS

Special thanks and acknowledgment are made to those individuals and organizations whose assistance was helpful in the development of this report.

The following contributors provided information and perspectives through personal communications:

Louis Deziel, Atelier - Menlo Park, CA

Dick Fisher, Don Webb, Joel Hornack, Voith Hydro - York, PA

Pat March, Hydro Resource Solutions LLC - Norris, TN

Bert Milano, U.S. Department of the Interior, Bureau of Reclamation - Denver, CO

Peter Rozzini, New Brunswick Power Corporation - Fredericton, New Brunswick, Canada

David Tubbs, Southern Company Generation - Birmingham, AL

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INTRODUCTION

Increasingly, owners and operators of hydroelectric plants are operating their plants in ways that impose greater stresses on the facilities now than in the past. In some instances, these stressful circumstances are a consequence of utility industry restructuring. Some restructuring scenarios shift a greater burden of providing special electrical services, known as *ancillary services* (A/S), to hydro plants. In other instances, the shift is driven by utilities seeking to make their electrical systems more efficient.

A/S - A Core Competency

There has been great emphasis in recent years, both within utilities and throughout the broader business community, on focusing on core competencies as a way to increase operating efficiency and reduce the costs. In this framework, the shift to hydro plants as a provider of A/S has merit. As a rule, hydro plants are very good at providing these services; therefore, providing A/S is a core competency of hydroelectric facilities.

A/S, that is, the special electrical services that must be provided within electrical networks to ensure stable and reliable operation, include:

- Regulation and frequency response
- Reactive power and voltage control
- Operating reserves, both spinning and supplemental

Although there are other types of A/S, these are the most common. Recent research by EPRI recognizes that hydro has a strong role to play in providing these A/S products [1].

Regulation and Frequency Response

Electrical networks are complex assemblages of generation sources, loads, and interconnecting transmission and distribution systems. Regulation power (which provides a small amount of the total power supply) is used to fine-tune the network for stable and reliable operation. Typically, major baseload sources provide bulk power supply. These sources can include large thermal (coal and nuclear) or larger hydro units, and such sources have a high degree of inherent inertia. Basically, they cannot respond rapidly to small changes in load. Especially with a thermal unit, a change in unit loading initiates a complex series of events that cascades through multiple systems, requiring substantial time for a unit to reestablish stable operation at a new level of output. The perturbations of routine system operation are handled by smaller or more flexible units (such as hydro units) that are capable of more rapid adjustment to system loads.

Reactive Power and Voltage Control

Ideally, electrical transmission and distribution systems would operate at unity power factor: the condition in which line voltage and current are “in phase” and resistive line losses are minimal. In actual operating systems, however, inductive loads (for example, motors) and line inductance cause systems to operate at less than unity power factor, resulting in electrical (and economic) losses. The power factor can be corrected through a variety of means. Using generators remote from baseload facilities is one way to correct the power factor and improve the efficiency of network operation in the plant’s region, often saving a multiple of the energy required to be supplied as reactive power.

The simplicity and responsiveness of hydro generation units often make such facilities ideal for providing the rapid response capabilities needed for supplying ancillary services. In some cases, the small size of hydro units (in comparison to an overall electrical network) or remote distribution can be advantageous.

Operating Reserves

Whereas regulation power and reactive power supply are used for fine tuning an electrical system’s operation, operating reserves enable a system to accommodate major unexpected contingencies, most commonly, the failure of a generator. (It is also important that systems be prepared for loss of load; however, this contingency is more easily accommodated in the basic designs of many types of generation units.) The principal way of preparing for events that call for rapidly supplying a large amount of power is to operate the system so that a percentage of the generating capacity, for example, 5 or 10%, is not being used. Then, when a demand occurs (for example, by loss of a generator), sources with available capacity can be “ramped up” to cover the deficit with spinning reserves. Alternately, some operating reserves are maintained in a state of readiness, as supplemental reserves to provide capacity as a contingency.

Strategies for Accommodating A/S

Hydro units often are well suited to supplying A/S. However, if these services result in a new mode of operation, they can pose problems for owners and operators. Although the problems might be balanced by new and possibly important economic opportunities, plant managers need to be aware of the implications that might result. One or more of the following strategies might need to be pursued:

- Upgrading key components to support A/S operations
- Installing monitoring equipment for anticipating/avoiding equipment problems/failure
- Bolstering operations and maintenance programs and budgets to support more severe operating requirements
- Reserving funds for replacement of key equipment items due to reduced life expectations

Performing a “wear and tear review” can be a beneficial exercise for many hydro facility managers where the operational mode has been changed—or where change is contemplated—to provide A/S. Such a review can highlight the need for implementing one or more of the foregoing strategies.

Practical Approaches for Dealing With Wear and Tear

A thorough review of the literature relevant to wear and tear failed to reveal much published information that would be directly useful to hydro generation facility managers. Instead, the most useful information—the collective experience and practices of many managers, engineers, and operations and maintenance staff throughout the industry—appears to be unpublished. However, owing to resource limitations, no major effort could be made to either capture or sample this collective knowledge. It should be noted that a fair amount of effort is being expended in investigating this topic, both internally by power producers and by the industry at large. Table 1-1 summarizes this effort. The information contained in this report is necessarily somewhat anecdotal and less comprehensive than might be desired. Nonetheless, the ideas and suggestions presented can provide a useful framework that individual managers can use as a guide in appraising their specific situations.

It would be of value to have a well-defined characterization of wear and tear in terms of its overall costs and effects as brought on by A/S operation. However, no such characterization has been found in, or deduced from, available information. Yet two rough rules of thumb were identified. One rule, used in previous EPRI analyses, is that one start-stop of a hydro generating unit has an aging effect equivalent to 10 hours of routine operation [2]. The other rule, from a European investigation, is that for hydro units in the size range of 20–100 MW, the cost per start was $130–$330 [3].

Little scientific data are available on hydro unit wear and tear. However, some work done by EPRI in the fossil-fueled generation field can be used to determine an appropriate direction. In addition, some limited calculations have been performed that indicate the type of wear and tear analysis that is possible. Some data have been obtained from manufacturers and consultants, but opportunities exist to gain more. The experience of pumped storage operators might be another good source of data.

Table 1-1
Summary of Ongoing Research Related to A/S

A/S Topical Area	EPRI Reference	Conclusions and Extensions to Hydro
Services provided by hydro generators	Mechanisms for Evaluating the Role of Hydroelectric Generation in Ancillary Service Markets [1]	– Hydro has a competitive edge in supplying some A/S, including regulation, load following, and reserves – The hydro operator must understand the operating cost and the opportunity cost of providing these services
Quantity, quality, and certification	Measurement of Ancillary Service From Power Plants: Regulation, Load Following, and Black Start [4]	– Regulation and load following measurement and testing are straightforward – Black start demonstration is more difficult
Costs and effects of providing A/S	EPRI reports on fossil-fueled power plants: – Cost of Providing Ancillary Services From Power Plants: Regulation and Frequency Control [5] – Cost of Providing Ancillary Services From Power Plants: Reactive Supply and Voltage Control [6] – Cost of Providing Ancillary Services From Power Plants: Operating Reserve - Spinning [7]	
	Hydro experience: – Pumped storage – Manufacturers/consultants	Developed in this report on a preliminary basis; potential area for additional in-depth research
EPRI methodologies	Calculating Cycling Wear and Tear Costs - Methodology and Data Requirements [8]	Methods to derive wear and tear costs of components
	Methodology for Costing Ancillary Services From Hydro Resources [9]	Discusses five cost components: – Lost opportunity costs – Efficiency losses – Incremental operation (dispatch and scheduling) – Indirect costs, such as software – Wear and tear costs as a function of equipment life and increased maintenance
Wear and tear of hydro units operating for A/S	Tech Roundup Report V4 (this report)	– Methodology applied – Further considerations

From a practical standpoint, the evolving analysis and understanding of wear and tear of hydro units operating for A/S can be presented in two broad areas:

- First, acknowledgment is needed that certain hydro components incur an inherent risk in operating for A/S and that some prospective problem or failure can be anticipated. The consequences of component risks occur over time, and remedial actions include monitoring and prevention, mitigation, or repair actions. Table 1-2 begins to develop the concept of dealing with wear and tear and incorporates judgments about the relative consequences and costs of failure events and remedial activities.
- Second, a methodology for calculating these additional wear and tear costs needs to be developed so that hydro owners and operators can incorporate appropriate changes into their operating strategies. A methodology is developed in Section 4 that illustrates a practical application to hydro unit components.

Table 1-2
Approaches for Dealing With Hydro Unit Wear and Tear

Prospective Problem/Failure	Consequences (Minor, Major)	Frequency or Timeframe for Occurrence (Short-, Medium-, Long-Term)	Remedial Action	Implementation Effort/Cost (Low, Medium, High)
Runner cavitation	Minor Major	Short-term for repair Long-term for replacement	Monitor/repair Replace	Low High
Wicket gate cavitation, bushing wear	Minor Major	Short-term for repair Long-term for replacement	Monitor/repair Replace	Low High
Hydraulic actuators seizing	Major	Medium-term	Monitor/test oil, check seals	Low (rare)
Servomotor failure	Major	Medium-term	Monitor/test oil, check seals	Low (rare)
Thrust bearing failure during startup	Major	Long-term	Install oil-lift pump	Low
Generator stator winding failure due to mechanical loosening of coils in slots	Major	Long-term	Periodically measure coil tightness and re-wedge coils as needed	Medium
Generator rotor winding failures due to vibration or thermal cycling	Major	Long-term	Periodically inspect	Medium
Brush life reduction	Minor	Short-term	Inspect and maintain	Low
Circuit breakers, switchgear, transformers failure	Minor Major	Short-term Long-term	Inspect/recharge Replace	Low Medium
Air Compressors	Minor	Short-term	Replace	Medium

Report Organization

Based on the clear need and interest in defining and estimating the wear and tear of hydro units operating to provide A/S, this report was designed around the following elements:

- Audience - hydro project operators faced with a competitive electricity market and new operating rules for optimization that can have a large impact on operation and maintenance (O&M) costs.
- Scope - wear and tear effects on hydro units operating to provide A/S. Table 1-1 summarizes available research.
- Application - wear and tear in a generic sense as related to hydro unit operation and maintenance, recognizing that the development of independent markets for A/S product definitions and pricing vary among regions.
- Terminology - definitions of the six categories of A/S according to FERC Order 888 are described in Section 2. The first four listed are well-matched to hydro resource capabilities and are the focus of the discussion [1]:
  - Regulation and Frequency Response Service (RF)
  - Reactive Supply and Voltage Control from Generation Sources Service (RV)
  - Operating Reserve - Spinning Reserve Service (SP)
  - Operating Reserve - Supplemental Reserve Service (SU)
  - Energy Imbalance Service (EI)
  - Scheduling, System Control, and Dispatch Service (SC)
- Wear and Tear - any damage in power plant components arising from operation. Therefore, the baseline for wear and tear would be that experienced under historically normal operations—whether run of river, baseload, or peaking. Wear and tear of units operating for A/S would then be the incremental damage to unit components as a result of altered operations.
- Purpose - address hydro owners’ and operators’ need to account for wear and tear factors, in terms of modifications in equipment and procedures.
- Focus - information for estimating wear and tear costs to provide practical guidance for accommodating wear and tear.

This report is organized into seven sections, including this introduction. The additional sections are:

- Section 2, “Understanding the Need,” discusses background information and what drives the need to understand wear and tear, including:
  - A/S terminology and marketplace
  - An introduction to operating conditions that affect hydro unit wear and tear

- Section 3, “Wear and Tear Effects on Hydro Units,” contains background information on:
  - Component analysis as developed for fossil-fueled units
  - Extension to hydro units, including the experience of pumped storage units
  - Hydro unit wear and tear prioritization and analysis
- Section 4, “Wear and Tear Methodologies,” presents and expands on an EPRI methodology [9] developed under the Hydro Asset Management (HAM) Target and applies the methodology to a generic hydro plant. Wear and tear of plant components are then allocated to ancillary service products in the example calculation.
- Section 5, “Research Activities,” includes ongoing research and recommendations for further consideration.
- Section 6, “Observations and Conclusions.”
- Section 7, “References.”
- Appendix A, “Hydro Unit Wear and Tear Exercise,” contains the data and discussion of an exercise conducted to begin to quantify wear and tear for various hydro units operating for A/S.

2
UNDERSTANDING THE NEED

In the wake of electric utility restructuring, many hydro owners and operators need to know accurate costs of providing not only energy and capacity, but also A/S. Such services have often been provided, but not accounted for or priced separately. Knowledge of the actual cost to provide a specific service, including effects of wear and tear on a plant component, is needed for establishing the value of A/S and for prudent facility management.

Hydro Asset Management

Why Hydro Owners and Operators Are Looking at Plant Operation

The late 1990s saw dramatic shifts in electric utility structures. In 1996, FERC Orders 888 and 889 established a basis for the development of a competitive bulk power market, and many states took steps to foster competition in electricity supply. Regional independent wholesale markets for bulk power and services were promulgated. Responding to these initiatives has required significant changes in utility structures.

Market forces have required that owners and operators of all generating facilities rethink all facets of costs. Whereas electricity has been historically sold and exchanged based on market values for energy (kWh or MWh) and capacity (kW or MW), the new electricity markets place value on the special A/S that were simply embedded in prior (pre-restructuring) electricity products and not priced separately.

These new markets provide a significant opportunity to entities that can supply these high-value A/S. On the other hand, it costs more (per kW or kWh) to provide the capacity and energy that are used as operating reserves than, for example, baseload power. It is important to have a good understanding of the costs involved. Wear and tear—and *increased* wear and tear—are among these costs.

An easy-to-understand example of how value can be added by hydro units in a multisource generation system is described in the article “Increasing Hydro Use: One Solution to Controlling Rising Utility O&M Costs” [10]. This article describes a study in which production costs were modeled over a 10-year period. Fossil-fueled and dispatchable hydro units were used, that is, hydro that has storage available was used so that power can be generated and dispatched whenever needed by the system. On a projected basis, the study showed that operating a generation system with a dispatchable hydro unit component could avoid substantial cycling costs of fossil-fueled units, thus adding extra value to the system due to the hydro generation component. The cited article suggests that hydro can contribute substantial extra value to a combined system. For the case examined, additional daily costs of about $160 for hydro unit operation were estimated to deliver long-term savings (in terms of reduced fossil unit wear and tear) of more than $50,000.

What Hydro Owners and Operators Have Done - Benchmarking

In order to understand the competitive reality of hydro operation in a restructured electric utility market, a benchmark study of hydro unit operation was undertaken by hydro utilities in the 1990s. Table 2-1 summarizes some of the relevant statistics related to O&M practices. Clearly, the magnitude of dollars spent per unit is substantial.

Table 2-1
Hydro Unit Operation and Maintenance Benchmark Data

	1994 HCI Benchmark Study	1996 HCI Benchmark Study
Average O&M costs	$16,645,000	$15,262,000
Number of units	955	2100
MW	40,100	66,500
Average maintenance	Not available	$6,800,000
Average maintenance per unit	Not available	$197,379
Average O&M costs per unit	$658,700	$443,000
Average cost per MW	$17,409	$23,100

Reference: [11, 12]

A survey presented the rehabilitation practices of 29 hydro organizations representing 485 conventional plants and six pumped storage facilities with a combined capacity of 54,000 MW [12]. A portion of the survey described the strategy for operation and rehabilitation decisions. Overwhelmingly, modernization of all major components is favored (79%). However, a no action run-to-failure strategy was also a consideration 52% of the time. Increasing preventive maintenance was also considered as a strategy 25% of the time. Another point of interest was that data on start-stop cycles were maintained by 50% of the responding hydro organizations, while detailed maintenance records are maintained by over 80% of the respondents.

While these benchmarking results are informative, such information alone cannot provide a basis for determining the costs of A/S or for managing hydro units effectively to produce A/S.

What Hydro Operators Will Need to Do

In order to take advantage of opportunities for producing valuable A/S products, hydro operators need to do the following:

- Understand the terminology and monitor the market value of the A/S in the regional marketplace
- Study, strategize, and modify operations to maximize values and minimize costs
- Account for the total cost, including wear and tear effects, of providing the A/S from hydro units

A/S Terminology and Market

FERC Order 888 defines six categories of A/S. This report focuses on the first four categories, neglecting Energy Imbalance and Scheduling, System Control, and Dispatch Service. Focusing on four categories is consistent with EPRI HAM work [1].

Regulation and Frequency Response

RF is provided for transmission within or into the transmission provider’s area to serve load in the area. The regulation service obligation can be provided by generation with automatic generation control capabilities that responds to moment-to-moment fluctuations in frequency and interchange to balance load with generation—automatically and in real time.

RF uses the same equipment and is offered as part of one service product. Regulation is accomplished by committing on-line generation whose output is raised or lowered predominantly through the use of automatic generating control (AGC) equipment as necessary. This regulation service can also be considered load following and can be segregated into system generation up and system generation down components, as in the California market.

Reactive Supply and Voltage Control From Generation Sources

RV is the provision of reactive power and voltage control by generating facilities. This service is necessary in basic transmission service to maintain voltage on the transmission system.

This dynamic service is generally defined as the provision of electric generators to inject or absorb reactive power to maintain voltage on the transmission system within required ranges. Generators can supply reactive power while generating and also in a synchronous condenser mode, that is, without the turbine.

Operating Reserve - Spinning Reserve

SP is provided by generating units that are on-line and loaded at less than maximum output. They are available to serve load immediately in an unexpected contingency, such as an unplanned outage of a generating unit.

This type of reserve capacity is spinning and synchronized to the grid and must begin to respond immediately and be fully on-line typically within 10 minutes. Hydro units, in general, have a quick response and make good spinning reserve units. However, operating at part-load means lower efficiency. Cavitation, vibration, and oscillations can also occur, making certain units impractical to provide spinning reserves in the generating mode. Some hydro units can be synchronized at a partial load, or minimum flow, or provide this service as a synchronous condenser, that is, spinning in air.

Operating Reserve - Supplemental Reserve

SU is generating capacity that can be used to respond to contingency situations. Supplemental reserve is not available instantaneously, but within a short period (usually 10 minutes). It is provided by generating units that are on-line but unloaded, by quick-start generation, and by customer-interruptible load.

Sometimes referred to as *standby* or *non-spinning reserves*, SU is defined as reserve capacity that need not be spinning, but must be fully on-line (typically within 10 minutes). Auxiliary systems must be kept in a state of readiness, and adequate water must be available to provide this reserve service. Typically, although this varies with the system and the particular demand, the unit is started on demand, run for a limited period, and shutdown and returned to supplemental status.

A subset of this service that can be provided in certain jurisdictions is replacement reserve. Replacement reserve requires that a unit is on-line within 60 minutes. This slightly more flexible reserve allows minor scheduled maintenance outages that do not require unit disassembly to take place while the unit is supplying reserve.

Other A/S

Additional A/S (not discussed in this report) include the following:

- EI - accounts for the deviation between the scheduled and actual delivery of energy to a load in a local control area over a single hour.
- SC - is a basic requirement of providing transmission service. This service can be provided to schedule the movement of power through, out of, within, or into the control area. It includes the dispatch of generating resources to maintain generation/load balance and maintain security.

- Other A/S can be offered, including the following:
  - Dynamic Transfer (DT) - the transfer of dynamic power properties across load control areas
  - Real Power Transmission Losses (TL) - computed as transformer and transmission line losses due to wheeling
  - System Black Start Capability (BS) - the restoration of transmission network following network failure, using generation system resources

A/S Marketplace

Prepared by the Brattle Group, EPRI TR-111707, *Mechanisms for Evaluating the Role of Hydroelectric Generation in Ancillary Service Markets* [1], addresses the issue of how best to operate hydroelectric facilities within new market-based power sales structures. The report focuses on three classes of A/S of special interest to hydro generators: regulation, spinning reserves, and supplemental (non-spinning) reserves.

Three approaches were used to develop the study. One approach was a case study of a western hydro generator and the value of providing reserve services. A second approach surveyed 17 hydro generators and focused on their A/S operations. A methodological study, modeling conditions when hydro is more profitably scheduled as reserve capacity rather than for spot energy, was also developed.

The survey focused on utilities with an excess of 400 MW of hydro capacity and where hydro accounted for at least 10% of their capacity. The following three key areas were pursued:

- Non-electric limitations that restrict the operation (for example, flood control, irrigation, and fish protection)
- Characterization of the hydro systems' basic operations (for example, seasonality and peak versus baseload)
- Description of the use of hydro facilities to provide reserves and tradeoffs

The report offers several conclusions, all pointing to the fact that restructuring will likely increase the value of hydro resources. To maximize these opportunities, hydro owners and operators need to adjust O&M and scheduling to better respond to market conditions. In a restructured electric market, water availability and usage for energy production are not the only factors affecting operation. Hydro resources must adapt to follow pricing of A/S, not load, to maximize value.

The report suggests that hydro scheduling will evolve to be "all or nothing," that is, hydro facility operation might evolve to a schedule that runs at maximum capacity during high-price times and at minimum capacity or in spill mode during low-price times. The report suggests that even a modest reserve availability payment might justify leaving the unit in standby for supplemental or replacement reserve utilization. Another interpretation would be that a hydro unit might be operated at minimum flow, as spinning reserve, up to a trigger price. At the trigger price, the unit would be loaded to its full capacity for a short duration and return to a minimum as market prices drop. Clearly, in this type of operation, the incremental wear and tear of start-stop operation will affect costs and strategies for conducting and scheduling O&M work.

Another scheduling issue related to production costs is the likelihood of increased requirement for hydro-thermal coordination. Optimum reserve pricing will be driven by the competition between hydro and thermal O&M. This observation notes that "hydro has no fuel cost and only modest incremental maintenance costs from variations in how it is scheduled compared to thermal units startup, shutdown, and partial loading" [1]. This modest incremental maintenance should be quantified, but how?

The report indicates that hydro's advantage will be greater for fast reserve products, that is, regulation and spinning. Non-electric constraints (such as minimum flows, fish passage, and mitigation requirements) are unlikely to significantly prevent this type of reserve operation. Short-term (hourly) operation to meet reserves should not be affected by environmental, flood control, recreational, and irrigation demands. However, short-term startups and shutdowns indeed might affect wear and tear costs.

The Technical Advantages of Hydro

In summary, TR-111707 concludes that:

- Hydro has a competitive advantage over other forms of generation for supplying regulation, reserves, and load following
- The hydro operator must understand both the operating cost (including wear and tear) and the opportunity cost of providing these reserves at market

The technical advantages of hydro over other sources of generation to provide A/S are shown in Table 2-2. These can be summarized into five categories:

- Fast response. Hydro units have a quick response to a signal to start, stop, change loading, or respond to frequency or voltage needs. While this varies with unit type, hydro generally can respond within the 10-minute time frame for supplemental reserves and even provide replacement reserves within 60 minutes. How fast is fast enough for reserve service? This term varies with different regional electric pools, and definitions continue to evolve. It should be noted that hydro facilities' ability to respond might be governed by downstream notification issues, even though the units might have the hydraulic and mechanical ability to respond more quickly.
- Part-load efficiency. Hydro units can operate at partial gate over a wide range. However, the rough operating range and the direct impacts on bearings and cavitation must be considered. It will become important to define operating constraints and to train operators accordingly. These measures will help avoid the production of A/S that could subject the equipment to excessive, and unjustifiably costly, wear and tear.
- Controllability. Hydro units are more controllable because of sophisticated governors and direct control of fuel (water). Most hydro units can respond up or down, on or off, substantially more easily and quickly than other generation sources.

- Startup/shutdown. Hydro units have perceived nominal startup costs compared to other forms of generation. But even for hydro, these costs are not zero. Quantifying and minimizing the startup/shutdown costs will be key to gaining value.
- Lower maintenance costs. Hydro units have traditionally had lower maintenance costs than thermal units. Will shifts in operation significantly increase long-term wear and tear of hydro components?

Hydropower generation clearly has attributes that make it suitable for adaptation to serve high-value A/S markets.

Table 2-2
A/S and Hydropower Response

A/S Product	Hydropower Capabilities
Regulation and frequency response	– Fast response and controllability available – Part-load efficiency superior to other generation – Lower maintenance cost an advantage for hydro
Reactive supply and voltage control	– Ability to supply product during generation and in synchronous condenser mode – Offset by costs associated with generator and excitation losses and power consumed to motor
Operating reserve - spinning	– Fast response and controllability available – Part-load efficiency capable but recognized wear and tear – Lower maintenance cost an advantage
Operating reserve - supplemental	– Fast response on-line – Nominal startup costs over other forms of generation

Reference: [1]

Hydro Unit Operation

Understanding hydro unit operation and defining the period of time a unit supplies a particular A/S is one element of developing wear and tear costs. A recent paper developed by the Bureau of Reclamation provided a methodology for calculating total production costs for ancillary generation services based on known O&M costs and then allocating them over operating time periods [13]. These operating states or modes are described as:

- Generating - a unit in the generation mode provides an energy and capacity product and technically contains no ancillary services. However, by generating, the unit can provide A/S as follows:
  - Regulation services can be provided while generating, based on a signal to increase or decrease the unit loading within the regulation bandwidth of ±10% of the unit rating. Quantifying the incremental swings, both in terms of number of times and magnitude over the period of operation, results in the total regulation hours.
  - Voltage support (reactive power) while generating is a level that is defined so as not to impact the maximum operating capacity of the units.
  - Spinning reserves in the amount of incremental generation to maximum load could be provided if the unit is generating at part load. These ramp-ups and ramp-downs could be counted over a generating period.
- Not generating or standby - a unit not generating can provide A/S as follows:
  - Supplemental and replacement reserves (non-spinning) can be provided by a unit in a standby mode if there are no limitations on water usage and readiness
  - Synchronous condenser service, providing reactive power without generation, can be provided in non-generating periods

Wear and Tear Effects

Segregating the operation of a unit into operating modes and then allocating expenses to each product seems simple. However, determining component life reduction resulting from increased wear and tear for alternate modes of operation is far from simple.

The EPRI-sponsored *Hydropower Reliability Study* provides insight into the requirements for assessing component life and plant aging as a result of different operation modes [2]. Table 2-3 presents possible wear and tear effects on hydro components to account for operating conditions to provide A/S. These data provide a framework for the study of wear and tear effects, expanded in Sections 3 and 4.

Table 2-3
Wear and Tear Effects on Hydro Components During A/S Operating Modes

Hydro Component	Operating Modes Providing A/S			
	Generating		Standby	
	Part Load for Spinning Reserve, Voltage Support, and Frequency Regulation	Full Load for Voltage Support and Frequency Regulation	Startup and Shutdown for Supplemental Reserves	Synchronous Condenser to Provide Reactive Power and Voltage Control
Turbine runner and blades	Cavitation due to part-load operation	Possible?	Wear as a result of unsteady states	Possible?
Wicket gates, inlet valves, and actuators	Maintaining and changing wicket gate opening position	Maintaining and changing wicket gate opening position	Opening and closing; wear of bushings and cylinder seals	Closed—requires pressure to prevent leakage
Generator stator and rotor	Partial load heat stresses	Full load heat stresses	Overcoming inertia and heat cycle effects	Cycling stresses
Excitation, breakers, and switchgear	N/A	N/A	Contacts closing and opening	N/A
Transformer	Partial loading	Full load	Heat cycle effects from startup/shutdown cycles	Heat cycles
Auxiliary equipment (air compressors)	N/A	N/A	Increased operation to supply air to brakes or to pressurize draft tubes	On to supply air for maintaining suppressed tailwater level
Controls and instrumentation	Monitoring and adjusting status; automatic operation	Monitoring and adjusting status; automatic operation	Increased monitoring of status; increased automatic operation initiations	Possible?

Reference: Adapted from *Hydropower Reliability Study* [2]
N/A = Not Applicable

3
WEAR AND TEAR EFFECTS ON HYDRO UNITS

Previous EPRI documents have focused on wear and tear of fossil-fueled units. By reviewing the experience of pumped storage units and extensions to hydro units, an understanding of the mechanisms for evaluating wear and tear of hydro units can be achieved.

Wear and Tear Costs for Fossil-Fueled Units

Several EPRI reports on the costs of providing A/S from fossil-fueled units were reviewed:

- *Cost of Providing Ancillary Services From Power Plants: Regulation and Frequency Response* [5]
- *Cost of Providing Ancillary Services From Power Plants: Reactive Supply and Voltage Control* [6]
- *Cost of Providing Ancillary Services From Power Plants: Operating Reserve-Spinning* [7]

Most of the fundamental concepts applicable to wear and tear of hydro units can be inferred from these reports.

Cost of Providing Ancillary Services From Power Plants: Regulation and Frequency Response [5]

The objective of this EPRI study was to define regulation and frequency response service and provide a methodology that can be used to determine the variable cost for a steam cycle generating unit to provide this A/S [5]. Regulation and frequency response service shall include all rapid load changes (moment to moment) to meet instantaneous load demand, balance a control area supply, and maintain frequency.

Because AGC signals correct for frequency, operating under AGC will provide some degree of frequency regulation. Active speed control or governor systems also provide frequency regulation. The EPRI study identified the additional cost incurred at the power plant level for providing regulation and frequency response. The following is the process defined in the report:

1. Define the unit and obtain relevant performance data
2. Determine the load range, schedule, and time period for service
3. Define the operating modes, either base case or A/S regulation frequency response mode

4. Determine the additional fuel, repair, and other costs associated with the service

5. Calculate the variable cost of the service in terms of dollars per hour, day, month, year, or an additional cost (mils/kWh) of energy produced while providing the service

The report suggests potential wear and tear costs associated with regulation and frequency response service at the unit level for fossil-fueled units. The report goes on to define a spreadsheet methodology for a thermal unit and to calculate a generic 350-MW hypothetical example. While the fossil-fueled unit results are not relevant, the following overall conclusions provide insight to understanding hydro wear and tear:

- Regulation and frequency response is a new service. No evaluation of costs in this manner has been performed before.
- The methodology might need to be adapted with practice.
- Case studies to date (on thermal plants) indicate that the specific cost (including fuel) for frequency response service is not very large, between 0.5 and 1.5 m/kWh or about 1–3% of the kWh cost at each station.

Cost of Providing Ancillary Services From Power Plants: Reactive Supply and Voltage Control [6]

The objective of this EPRI study was to provide a methodology for calculating the variable cost to a power generating station to generate reactive power (volt-ampere-reactive [VAR]) required by the loads connected to the power system and to the transmission equipment itself in thermal plants [6].

To produce VARs, the variable cost of operating in a power factor range of 0.9 to 0.8, as opposed to a unity power factor, must be considered. With power factors below unity, additional reactive current flows in the generators, increasing the total current and associated resistive (I^2R) and stray (eddy current) losses in windings. The following definitions and distinctions are related to costs:

- Variable costs of VARs are defined as the costs of generating a given real and reactive power into the system at the voltage required by the particular system, less the cost of generating the same real power (only) at unity power factor.
- Maintenance consists of the known operations required to optimize the cost of operating the plant reliably.
- Repairs are defined as nonroutine maintenance. Replacement of minor components or part of a major component (such as a stator winding bars within a winding) would constitute a repair.
- The effects and costs of plant aging can be defined as occurring when a major component is replaced in its entirety because component reliability, if repaired locally, is not sufficiently high. The distinction between plant aging and repair can be difficult (for example, when does one make a decision to completely replace a major component, such as a generator rotor, or to rewind the rotor completely?).

- While an event might have been the result of a localized failure, reliability of the whole is uncertain due to the accumulated effects of plant aging. Plant aging costs can be related to the differences in component replacement costs, comparing operating at a unity power factor versus replacement costs, when operating to produce VARs [6].

Example of Calculating Costs of VAR Production

The following example is excerpted from the EPRI report and summarizes the calculation of the cost of reactive power production [6]. Generating real and reactive power has two component costs: 1) cost of losses (generator and transformer, if part of the plant) and 2) variable costs—increased maintenance and aging—the wear and tear component.

Producing reactive power does not result in the production of saleable energy (kWh or MWh). However is does cost money to produce reactive power. Because the electrical current generated is higher, losses—mainly in the generator and, to a lesser extent, the transformer and transmission system—are greater. The increased currents, particularly in the generator rotor at lagging power factors, cause windings to operate at higher temperatures imposing greater thermally induced mechanical stresses, relative movements, and higher levels of vibration.

In order to calculate the wear and tear cost of generating VARs due to equipment maintenance, repair, and aging, the report suggests analyzing the historical operating and cost data. The methodology presented relates the maintenance and repair costs of VAR production by categorizing the dominant damage mechanism. It relates the historical power and VAR production that were responsible for the maintenance and repairs costs. To perform this analysis, it is necessary to have either knowledge of the maintenance cost history of the machine or the history of similar machines.

To determine the cost of aging, two methods are suggested. The simpler method is to make an estimate of the life span of the component, operated at zero VARs (unity power factor) and a second estimate for operating and producing VARs. For example, the life in the first case is 20 years and the life of the rotor and stator would be 12 and 17 years, respectively, for producing VARs (life reductions of 8 and 3 years). An alternate method would utilize probabilistic equipment failure rates, assuming that the production of VARs increases electrical loading accumulated damage and increases the failure rate.

In the analysis of costs associated with maintenance and repairs, the proportion of the costs associated with reactive power generation is determined by analyzing the historical incidence of costs and determining whether a cost is associated with a VAR-related damage mechanism such as stator current loading. Costs related to plant aging are separated and based on the likely effect VAR generation has on the expected life of the component and the annual charges required to pay for a future replacement (depreciation).

The results of this case study for a fossil-fueled unit are as follows. The generator has a history of being operated at full load and 0.85 power factor. The maintenance and repair records associated with stator end-windings due to vibration loosening the bracing has led to additional repair costs of $30,000 per year (average). It is assumed that a generator operating at 1.0 power factor could yield savings in the form of lower repair costs, resulting in reducing the VAR-related component of end-winding repairs by $8,400 per year (28% reduction).

The report suggests potential wear and tear costs associated with the production of reactive power based on maintenance records and offers the following insights related to understanding hydro generator wear and tear:

- The generation of VARs can have many effects, such as an increase in the rate of deterioration of stator end-windings.
- Repair to stator end-windings due to electromagnetic vibration loosening the bracing can be increased.

These factors might be responsible for many of the problems requiring routine maintenance and repair and are often a prime cause of equipment aging.

Cost of Providing Ancillary Services From Power Plants: Operating Reserve - Spinning [7]

This EPRI report aimed to provide a methodology to determine the variable cost of a steam cycle generating unit to participate in operating reserve - spinning service [7]. Many of the observations are relevant to hydropower units and are abstracted in the following.

Before the electric utility industry restructuring, operating reserve - spinning reserve was normally provided by each utility to cover its own load or within a defined load area. The variable cost of providing this service was not calculated separately, but simply considered a part of the cost of producing electricity.

Units that are on-line and loaded at less than maximum output provide spinning reserve service. They are available to serve load immediately in an unexpected contingency, such as an unplanned outage event. This capacity is synchronized to the grid, is in excess of the amount required to serve load, and is fully available within 10 minutes. A unit in spinning reserve can also provide regulation and frequency response if its speed control and governor are active and if it is connected to AGC.

An expected finding is that the specific cost of power generated in spinning reserve mode for a thermal unit can be quite high compared to the optimum cost of power from the same unit—due to poor heat rate of most thermal power units at low load.

Spinning resources operate generally for a 30-minute period until supplemental reserves are activated. Then spinning resources are returned to spinning reserve status 30 minutes after activation (a cycle). This procedure results in extra wear and tear maintenance costs associated with starting and stopping.

With respect to using hydro for spinning reserves, the report indicates that accurately defining the unit operating conditions that minimize wear and tear yet provide some margin for spinning reserves will be essential to appropriately price the ancillary product. Vibration, cavitation, and other damage mechanisms that are active at partial loading play a key role in determining these operating ranges and might limit a particular unit's ability to provide spinning reserve services. On the positive side, partial loading of some hydro units to accommodate environmental requirements (such as minimum flows) might provide an opportunity to provide this service, offsetting lost generation.

Application to Hydro Units

A review of the foregoing reports leads us to extend several observations to hydro units for each ancillary product and for potential damage mechanisms as well. Table 3-1 summarizes the potential damage mechanisms by hydro component and subcomponent. Most of these are a result of conditions that exist during operation and in combination with one another:

- Abrasion - hard particles moving against a surface
- Heat cycles - fluctuations of temperature
- Erosion - resulting from fluid action
- Adhesion - interaction between conforming surfaces
- Surface fatigue - repetitive compressive stresses
- Vibration - initiating event or harmonic setup

Table 3-1
Potential Increased Maintenance Activities and Fault Conditions Related to Providing A/S - Hydro Components

Component or Subcomponent	Condition/Problem	Wear and Tear Damage Mechanism
Turbine runner, stay vanes, blades	Inspection frequency increased due to running in less than optimal gate position for reserves	Cavitation
Wicket gates	Scoring of the guides Wear of the stems and bushings	Frequent adjustments for regulation Start-stop cycles can cause more frequent slipping or jamming
Kaplan hubs and blades; stems and bushings	Wear of the stems and bushings (galling)	Wear of the stems and bushings (galling) Cavitation
Inlet valves and seals	More frequent replacement	Increased operation, thermal changes, start-stop cycles.
Actuators; hydraulic cylinders, servomotors, and transducers	More frequent replacement	Wear as a result of very frequent movement/adjustment
Generator stator	Inspection frequency increased by need to check stator wedge tightness	Vibration
Stator windings	Inspection frequency increased by need to check slot wedge looseness/ slackness and fretting	Complex cause mechanism related to vibration and thermal cycling; insulation damage and abrasion can be related to magnetic conditions and vibrations
End-windings	Inspection frequency increased by need to check end-winding slackness and fretting	Insulation damage and abrasion can be related to conductor bar movement (vibration)
Core life	Core-end heating damage	High levels of leading VARs and pole-slip incidents
Generator rotor	Inspection frequency related to stator above	Vibration
	Displaced retaining rings Displaced packing bolts Stick-slip problems Inter-turn heating Asymmetric ventilation	Thermally induced vibration
Rotor windings	Ground faults Inter-turn faults	Generally affected by start-stop cycles, excitation current, or both
Brush life	Brush wear rate and replacement	Excess excitation brush maintenance that can be caused by production of VARs
Slip-ring replacement and refurbishment	Slip-ring wear rates	Might be affected by many factors including vibration, current density, spring pressure, and brush grade; generally dependent on magnitude of excitation current
Excitation	Faults on equipment	High levels of excitation
Circuit breakers, switchgear	Inspection and replacement of contacts/charging mechanisms frequency is increased due increased open/close cycles for startups/ shutdowns	Increased operation
Transformers	Increased inspection and maintenance/testing	Thermal changes due to partial- and full-load for short duration
Air compressors	Wear of system due to start-stop and continuous running	Increased usage/vibration for tailwater suppression
Controls and instrumentation	More frequent replacement	Wear as a result of frequent movement/adjustment

References: [5, 6, 7]

The following sections describe the various A/S and their potential effects on hydro unit components.

Regulation and Frequency Response

Areas of potential wear and tear costs associated with regulation and frequency response service at the unit level for hydro units can include:

- Additional duty and wear on the control components can be expected from frequent small yet continuous adjustments.
- Significant and frequent load changes are likely to cause more than normal wear on the control components, that is, wicket gates, stems and bushings, and their actuators and hydraulic cylinders.
- The turbine runner and wicket gates might generally be exposed to a more severe duty at a less efficient loading, thus causing increased metal fatigue and/or cavitation.

Reactive Supply and Voltage Control

Hydro generators also can operate in a “spinning in air” mode as a synchronous condenser, providing reactive power and voltage regulation to the transmission system. Typically, this is accomplished by closing the wicket gates and pressurizing the runner chamber with air to suppress the tailwater level below the runner. With the runner and generator rotating, the unit can spin at synchronous speed with low losses (the losses are only a few percent points and are due to windage and friction). Therefore, nearly the full capability of the generator is available to absorb reactive power or deliver it to the system. The unit can be quickly returned to the generating mode by releasing the air pressure and opening the wicket gates.

Production of reactive power can have several effects on hydro unit components, particularly during the transition from condenser mode to generating mode. As water enters the draft tube and runner chamber, the runner blades continue to spin, and a mixture of air and water impacts the turbine blades with significant turbulence (often called *churning*). This action places an increased load on the turbine during this purge period [14]. Production of reactive power can cause high wear and tear on ancillary equipment, such as air compressors and motors/pumps to maintain tailwater suppression.

Operating Reserve - Spinning

Effects on hydro unit components from providing spinning reserves might include:

- Cavitation effects as a result of partial loading
- Valve operation from frequent ramp-up/down
- Waterhammer from rapid changes

- Instrumentation stress from repeated cycling
- Wicket gate slippage from partial loading

These are all a function of operating at a partial load condition in readiness for ramp-up to maximum load.

Operating Reserve - Supplemental

The provision for supplemental reserves is most dramatically seen in the effects of start-stop cycles on hydro units.

Three IEEE papers on short-term scheduling of hydro units discuss the effects of stopping and starting of hydro units. These effects and costs are applicable to providing supplemental reserves and to some extent reactive power [3, 15, 16].

In a 1997 IEEE paper, the eight largest power producers in Sweden were interviewed regarding the startup costs of hydro units and their impact on short-term scheduling strategies [3]. The results of their interviews pointed to five aspects contributing to startup costs:

- Wear and tear on the windings due to temperature changes during startup
- Wear and tear of mechanical equipment during startup
- Malfunctions in the control equipment during startup
- Loss of water during maintenance
- Loss of water during startup

It was the paper’s conclusion that the first three items were the most significant to startup costs. They also found that startup costs would depend on the nominal power of the unit and the unit type. Startup costs are significant and should be considered in generation planning.

In focusing on startup cost relative to incremental maintenance, it is important to recognize that this cost is not an immediate one. While the benefits of the startup for providing supplemental or spinning reserves might be important in the short-term, the costs can accumulate on a unit over a period of years.

Another factor to be considered in the startup phase is the risk of malfunction in the control equipment. To the extent that a unit dispatch for A/S does not start up on demand, additional personnel and potential unavailability penalties might be incurred. This element can be significant for small, remote units operating infrequently.

The conclusions regarding startup costs of hydro-generators were that the cost ranged from $130–$330 per startup for units in the 20–100 MW range.

Example of Calculating the Wear and Tear Costs of Hydro Units During Startup

What are the elements of wear and tear during a startup? It is generally assumed that startups shorten the lifetime of the windings and also increase the frequency of maintenance. The following example was postulated for a generic 55-MW hydro plant:

- As a result of the change in temperature in the windings that occurs at startup, it was assumed that a startup decreases the lifetime of the windings by about 15 hours.
- 150 additional startups per year will decrease the life of a winding by 8.5 years (to 31.5 years).

Note: Some units have equipment controlling the temperature of the windings; these units will not be affected.

According to the same report, the costs of increased maintenance of the windings due to startups is about $125 per startup. This is based on the assumption that a change of the windings will cost $3.3 million.

The timing of the maintenance performed is important to the overall cost because maintenance performed during a high production season or during a forced outage is significantly more costly than maintenance performed in low season and as planned.

With regard to the costs of the malfunction of the control equipment, additional personnel costs, travel time, and repair were estimated at $70 per hour lost at, for example, two hours per malfunction and an estimated probability of 20% malfunction in the number of startups.

This adds an additional $30 per startup, resulting in a $155 per startup cost for this generic plant. While these data are anecdotal, the generic results represent a wide range of opinions regarding startup impacts on windings and control equipment [3].

This examination was extended further into the modeling of short-term hydro generation scheduling. With the premise that hydro units should be operated at points of good efficiency and that units should not be started or stopped too often because of the aforementioned costs, the authors pursued a dynamic programming model for optimal plant operation [15]. A secondary set of modeling research was conducted to examine modeling of spinning reserve requirements for hydro units [16].

Experience of Pumped Storage Plants

While not the focus of this report, the experience of pumped storage units can provide valuable insights into the wear and tear and damage mechanisms of conventional hydro units. Because these units are often designed for and experience multiple mode changes daily, the cyclic responses and resultant wear and tear on equipment components are relevant.

It was acknowledged that the number of starts required of a unit each year adds considerably to the aging effect of actual operating time. The equivalent aging effect of frequent starts was reported in a previous EPRI report that arrived at a value of 10 hours aging per start for hydropower generators [2]. This previous research related the number of hours of operation and starts per year to equivalent aging time. For example, a run-of-river plant with 6000 operational hours and 50 starts per year actually ages 6500 hours per year. By extension, a storage plant with one start per day (300 per year) generating 2000 hours per year actually has 5000 equivalent running hours of wear. The most dramatic effect is seen in pumped storage units with 4000 running hours and a postulated 800 starts per year (two mode changes per day). They have an equivalent aging of 12,000 hours per year or three times the actual operation.

How does this aging manifest itself in components of pumped storage units? A subsequent EPRI study reviewed the operation and maintenance practices of over 35 domestic and international pumped storage projects [17]. While these units are designed with severe duty and cycling in mind, their experience might shed some light on conventional wear and tear (Table 3-2).

Table 3-2
Wear and Tear Experiences of Selected Pumped Storage Plants

Component or Subcomponent	Condition/Problem
Bearings	Servomotor imbalance Out-of-round wear rings Uneven cooling
Generator stator	More frequent winding degradation as a result of insulation deterioration due to corona, temperature cycling, and age
Turbine runner	Cavitation present, but not considered significant
Unit circuit breakers	Generally under-designed for the pumped storage average duty of 1000 close-open operations/year
Valves	Excessive seal ring leakage
Wicket gates	Bearing wash out Shear pin failure Cavitation and peen marks

Reference: [17]

A/S Effects

The following is a summary of emerging concepts to explain the evolving nature of the effects of A/S on hydro units:

- Operation for regulation and frequency response. The rapid, frequent (but small) magnitude changes in unit response are difficult to quantify. Most likely, they represent a small impact on total costs and are most often absorbed in a normal operation and maintenance budget.

  However, there might be some instances in the case of older, larger units where bushing and bearing wear, as well as wicket gate attenuation, might be attributable to repeated operation in this mode. Appendix A suggests further testing for quantification in this area.

- The provision of reactive power and attendant wear and tear costs are focused primarily in two areas: (1) the auxiliary equipment needed to operate in this mode—the tailwater suppression or draft tube evacuation method, and (2) the effects on the generator, in terms of vibration and thermally induced stresses.

  Often, the station service energy costs far exceed any maintenance or replacement expenditures. So, while the additional wear and tear costs are recognized, they are not often quantified. With regard to the generator, previous EPRI research suggests that the cost of aging can be estimated by examining historical records and relating operational parameters with maintenance cycles associated with repair of stator end-windings or quantified using probabilistic equipment failure rates. Life reductions in the three- to five- year range are not uncommon.

- Partial-load operation, under any operating mode, is a known detrimental risk to the unit. Long periods operating at a rough running range for the provision of minimum flows or as spinning reserve accumulate.

  Cavitation monitoring, detection, and repair expenses for runners, wicket gates, and draft tubes can be estimated and allocated to the period of time spent in a particular loading condition. Ramp-up and ramp-down cycles also can cause thermal stresses to other components, although one would expect the cost to be less than a full startup/shutdown cycle.

- Start-stop cycles imposed on units operating for supplemental reserves can be a significant source of wear and tear costs, affecting many components.

  Not surprisingly, of all the wear and tear effects, start-stop has been the subject of most of the material reviewed. While the benefits of starting and stopping a hydro unit to provide short-term A/S (reserves) can be significant, the costs accumulate on the unit over the years and are generally thought of in terms of increased aging of the units.

  Other research has estimated the actual cost of startup, considering wear and tear of generator windings due to temperature cycles and effects on the mechanical equipment, to be in the range of $130–$330 per startup [3]. This range generally correlates with the information provided in Appendix A. Intuitively, repeated startups of warm windings should cost less than cold start windings and perhaps pose some mitigation possibilities if this operation mode is anticipated.

While these statements reflect a limited data set, they are a beginning to a clearer understanding of wear and tear methodology and the application of specific unit costs to component maintenance and repair.

Analyzing Component Wear and Tear

The processes developed in the EPRI fossil-fuel work on wear and tear suggest that in order to gain a good perspective on wear and tear, the various data related to unit and operating conditions should be collected for each component/sub-component and then prioritized in terms of most significant effects.

In the deregulated market, hydro units may or may not provide all A/S so generalizing wear and tear is somewhat difficult. However, defining an individual unit operation mode as described in Section 2 and then generally identifying which hydro components can expect wear and tear can be accomplished (Table 2-3). Furthermore, Table 3-1 expands the component analysis to identify potential increased maintenance activities and fault conditions arising from different operation. Capturing the total cost of all of these elements attributable to different operation modes is the wear and tear calculation following the methodology presented in Section 4.

Component Analysis

The identification of which hydro components incur the risk when operating for A/S will depend on the unit type and operation characteristics. However, it is apparent that four conditions might affect component wear and tear:

- Minor operation variations to provide voltage support and frequency regulation
- Synchronous condensing for reactive supply
- Partial-load situations providing spinning reserve
- Start-stop cycles that provide supplemental or replacement reserve service

Therefore, if the reaction of an individual component to any of, or a combination of, these conditions causes increased wear (think decreased life) or increased maintenance cost, that is the incremental cost of operating for ancillary services. Knowledge of the reaction and the possible solutions for both monitoring and mitigating the damage or recognition of a reduced life cycle provide the data for quantifying the total cost, by the aggregation of the individual component costs.

For example, if frequency regulation for a particular unit is a demonstrated A/S to be provided, then the repeated minor adjustment of wicket gates will show increased wear on the stem bushings and actuators. While in the past this was considered normal wear and tear, now in segregating services, this maintenance cost and frequency is related to providing A/S.

Similarly, if a unit is to be operated with significantly more start-stop cycles, then several components can be affected. The unit bearings might see increased wear that can be mitigated by the installation of an oil-lift system—a one-time cost. The generator might experience thermal cycling, perhaps mitigated by improved cooling or acknowledged as a life expectancy reduction requiring rewinding at an increased interval. A circuit breaker might have increased operations, with attendant wear of the contacts and more frequent replacement of SF6 bottles (if applicable).

Unit Variables

Table 3-3 summarizes the various factors and variables that can affect hydro unit wear and tear. These factors are unique to each unit and must be considered when evaluating the wear and tear cost.

Table 3-3
Factors and Variables Affecting Hydro Unit Wear and Tear

Variable	Information
Unit design/information	Age, design vintage, manufacturer
	Flow, head, capacity
	Turbine unit — Kaplan, Francis, horizontal, Pelton, speed, materials
	Wicket Gates — materials, actuators, hydraulics, bushings
	Regulation — variable or fixed blade
	Bearings — type, materials
	Generator — type size, speed, insulation materials
	Electrical control
	Hydraulic control
Operating history	Generation (average)
	Capacity Factor
	Loading characteristics — baseload, run-of river, peak/storage
	Time in different operating modes — standby, generating at partial/full load, planned/forced outage, synchronous condensing.
	Cavitation, vibration at % gate
	Number of starts/year
	Start attempt/success rate
	Capital expenses — related to components
	O&M expenses — related to components
Performance	Reliability %
	Availability %
	Maintainability — number of hours available to maintain without lost generation or lost availability
Miscellaneous	Climate
	Unit redundancy
	Environmental restrictions

Reference: [8] Adapted from Table 5-1

Interaction and Prioritization of Unit Components

An example of a procedure for prioritizing components for wear and tear analysis is in the EPRI report on fossil-fueled plants [8]. The procedure includes considering:

- The prospective *problem or failure* of a key component.
- The *consequences* of damage—minor or major. For example, providing 25 MW of supplemental reserves at x% gate position produces moderate cavitation, but 30 MW at z% gate produces severe damage.
- The *frequency* of the damage—short-term or long-term. For example, this would relate to turbine runner cavitation effects occurring at some partial load gate position and the percentage of running hours operating at that gate position to produce supplemental reserves. Assume a conventional unit generates 6000 hours per year (100%) and operates at best gate (85%), meaning it operates at partial gate (implying wear and tear effects) for 15%, or 900 hours a year. Further analyzing and categorizing the partial gate running hours to damage effects might arrive at 100 hours at low damage (x % gate), 500 hours at medium damage (y% gate), and 300 hours at high damage (z% gate). The overall frequency is then 300/6000 or 5% of the time incurs the most damage.
- The *remedial action*—in terms of increased monitoring, inspection, repair, replacement, or retrofit that could be accomplished to mitigate the damage or prevent the failure.
- The *implementation effort/cost*—low, medium, or high. Relating the costs to the frequency and consequences could be developed as a matrix with knowledge of the total unit cost—lost generation and value of accelerated maintenance.

This concept was developed in Table 1-2 for selected hydro components. Developing the attributes of each component would allow the prioritization of which components or sub-components need the most monitoring and analysis to determine wear and tear conditions and costs. In the above example, the turbine runner incurs high damage 5% of the year—a severe consequence—but its repair cost is medium or low because of improved cavitation repair materials and techniques. As a result, the actual wear and tear effects might be less important compared to the generator windings or another component within the unit. An understanding of the trade-offs for differing operating conditions and interactions with other components is suggested by this prioritization method.

This section had described:

- The operational modes to produce A/S
- The potential hydro component damage mechanisms
- The collection of data relevant to each component or sub-component
- A prioritization of the key components for the analysis

After the appropriate operation and maintenance data have been collected and analyzed, the next step is to apply a methodology for computing wear and tear costs. This topic is considered in the next section of this report.

4
WEAR AND TEAR METHODOLOGIES

Methodologies From Fossil-Fueled Generation

The EPRI report, *Calculating Cycling Wear and Tear Costs - Methodology and Data Requirements* [8], describes the development of a three-level methodology that power producers can use to calculate unit-specific incremental costs for cycling operation of fossil-fueled power plants. A review of this methodology gives indications as to how this method and data collection approach could be used for determining wear and tear costs for hydro units.

Within the document the term *cycling* is used to indicate all operating modes other than baseload, such as load following, peaking, or providing reserves. Cycling operations, either for voltage control/load following or repeated startups and shutdowns for reserves, cause long-term wear and tear. Wear and tear is used to refer to any damage to power plant components that occurs as a result of plant operation. This damage can be manifested as:

- Premature equipment replacement and repair
- Decreased availability and reliability

Cycling also causes short-term cost penalties including:

- Increased operation and maintenance costs
- Higher training needs
- Degraded equipment performance

Three draft methodologies for estimating wear and tear costs associated with cycling were proposed. Data requirements and sources to implement each of the methodologies are summarized in Table 4-1. The methodologies include the following:

- Level I - Top-down method using peer-unit average values based on industry-wide data, keyed to a few variables.
- Level II - Modified top-down approach that starts with the Level I correlation, but then provides a means to estimate the effects of a dozen or so key differences in equipment, operation, and maintenance of a specific unit compared to the peer group average.
- Level III - Bottom-up method calculates the wear and tear costs for plant components from knowledge of equipment condition, damage analysis, and detailed unit specific accounting.

Selecting and applying a methodology relies on the amount of data available. Because peer unit data for hydro units does not exist, we must assume we are operating in a Level III mode, building the wear and tear costs from the component level up. Given this methodology, the identified objectives of a wear and tear analysis, modified somewhat for hydropower operations, include the following:

- To evaluate the true cost of unit operation in various modes to allow for proper pricing of power transactions.
- To allow for unit commitment decisions through the knowledge of the true costs of operation. (For example, should Unit A be cycled on-off with Unit B base-loaded, or should both Units A and B be operated in the load-following mode?)
- To provide a means of benchmarking performance standards for units and personnel.
- To plan and budget for maintenance and capital expenditures.
- To predict increased repair/replacement requirements based on differing conditions of operation.
- To guide operators in real-time decisions about operating equipment differently.
- To provide operation information to support regulatory decisions. (For example, is there a way to agree to minimum flows at low-load situations, with the proviso that the unit could operate for brief periods as reserve?)

These objectives form the basis for conducting wear and tear analysis by components. Understanding the damage mechanisms, as well as having the information needed to mitigate a damage mechanism (for example, a modification, change, or retrofit) to reduce wear and tear will provide the inputs to the analysis. This concept is expanded further in the recent methodology developed for hydro units.

Table 4-1
Analysis Levels to Estimate Hydro Unit Wear and Tear Costs

Aspect	Level I	Level II	Level III
Nature of method	A top-down analysis relying on developing peer unit values	Top-down with modifications to account for unit differences	Detailed, bottom-up approach calculating information for individual components and units
Input required	General information about the unit and operations	Level I, plus differences in the design and operation compared to the peer units	Level II plus component specific costs
Who accomplishes this analysis?	Project manager	Project manger	Managers with input of cost support
Objectives	Estimates the cost of unit operation in various modes Modification of maintenance routines Increased observation of wear and tear effects	Same as Level I but with increased accuracy	Same as Level II but with the possibility of optimization of budgeting, planning, and economic dispatch
Expected accuracy	Good if peer units are relevant	Improvement over Level I	Highest level since component condition and damage rate considered

Reference: [8] Adapted from Table 1-1

Methodology for Costing A/S From Hydro Resources

As part of EPRI's on-going HAM research program, EPRI commissioned the development of a methodology for determining the total cost associated with providing A/S from hydropower plants [9]. The methodology lays out five elements of total A/S production costs:

- Lost opportunity costs
- Wear and tear costs (as a function of loss of equipment life)
- Efficiency losses (lost water when spinning)
- Incremental O&M (for unit start-stop)
- Indirect costs (power dispatchers and software)

Because of the lack of information in the industry on wear and tear and its effect on equipment life, the EPRI A/S costing methodology includes a technique for defining and estimating these costs using either a regulated or competitive business model. This wear and tear costing technique is summarized in Table 4-2. The technique provides for opportunities to minimize lost equipment life through additional maintenance projects. By using replacement cost rather than book value for calculating depreciation rates, it also provides a more current estimate of equipment cost.

To apply the technique, start with a base case operation mode that has three assumed parameters:

- An assumed reference operational mode
- An assumed life of the equipment components
- An assumed O&M budget for its remaining life

Similarly, the A/S operation case has a different operational mode, a different O&M plan, and different assumptions for the effects on components (such as reduced life).

The incremental cost of wear and tear of hydro units operating to provide A/S is determined by subtracting the base case costs from the A/S case costs.

Table 4-2
Wear and Tear of Hydro Unit Methodology

Step	Function
1	Compile the base case operating plan including output schedule and maintenance assumptions assuming no A/S production. Estimate the remaining life today of each component.
2	Compile the current assumed maintenance plan under the base case, that is, without A/S production.
3	For each component that you consider will be effected by A/S production: – Estimate the component's replacement cost using the same technology as the installed component. Include replacement project labor and engineering. – Estimate the new useful life of the component assuming no A/S activity.
4	Forecast A/S production over the course of a year. Estimate the total amount of activity for each product parameter that causes wear and tear. – For each component, identify and estimate the cost of additional one-time maintenance projects that would be used to mitigate life span reduction for the installed component. – For each component, identify and estimate the cost of additional periodic maintenance projects that would be used to mitigate life span reduction for the installed component. Maintenance activities already budgeted for in the base-operating plan should not be counted here because that would count their cost twice. Further, if A/S production would reduce the need for maintenance already assumed in the base-operating plan, then the cost of that activity should be credited to A/S by including it as a negative cost here.
5	– Estimate the remaining useful life of the installed component consistent with performing the maintenance projects in 4A and 4B. – It might be useful to think of this as a reduction in useful life compared to the base case.
6	– Estimate life assuming A/S operation (in years) for a new (replaced) component assuming that the A/S schedule is produced on a continuing basis and the incremental maintenance projects are continued over the new component's useful life. – Again, it might be useful to think of this in terms of a reduction in useful life compared to a new component.
7	Compute depreciation rates for a new component without and with A/S production: – New depreciation = replacement cost/new useful life – Mitigated depreciation for A/S = replacement cost/(new life assuming A/S operation)
8	Summarize the maintenance costs by: – Converting the cost of each assumed maintenance project to a prorated annual cost over the remaining useful life of the installed equipment. That is, one-time projects should be divided by remaining useful life; the cost of projects performed every other year should be divided by two. – Compute incremental annual maintenance expense by adding together the annual costs of all maintenance projects.
9	Compute total incremental wear and tear costs: Total wear and tear costs = Incremental annual maintenance charge + (mitigated depreciation – new depreciation)
10	Allocate total annual wear and tear cost to the A/S product classes according to how each product class was assumed to affect cost, as a percentage.
11	Compute activity cost rates for each product parameter by allocating the cost of each product class to the activity parameters and dividing by the assumed activity level.
12	(Optional Marketing Step) To estimate the cost of a proposed A/S schedule, calculate total activity for each product parameter and multiply these by the activity cost rates. (This step is not discussed in this Tech Roundup Report)

Reference: [9]

Note that it is possible for A/S schedules to have negative wear and tear costs. This situation occurs when A/S schedules reduce the wear and tear assumed in the base-operating plan. For example, if a unit was routinely scheduled to generate maximum output over compressed periods to capture the benefit of very high market prices, negative wear and tear costs could occur. If A/S product scheduling causes the unit to generate at a lower, less damaging output level over a longer number of days, wear and tear will be negative. Note that the loss of favorable prices will be captured elsewhere as a lost opportunity cost.

Wear and Tear Methodology Applied to Generic Hydro Unit

The following generic example is an application of the foregoing methodology and serves to illustrate the concepts involved.

The methodology (Table 4-2):

- Compares a base operating case to an A/S operating case
- Postulates effects on components maintenance schedules and lifetimes (Table 4-3)
- Calculates wear and tear (Table 4-4)
- Allocates the costs to individual ancillary service products (Table 4-5)

This example is organized by the following elements and references the steps in Table 4-2. The costs developed by working through the methodology result in a total estimated wear and tear cost of nearly $28,000 per year given these assumptions. Extending this analysis further, the allocated costs of wear and tear by ancillary product can be postulated as shown on Table 4-5.

Background and Hydro Portfolio

For simplicity the generic example features a single project with a one-unit 15 MW powerhouse, commissioned in 1988. Therefore, it is 12 years old today. The project consists of a water conveyance system (intake, tunnel, and penstock) and a powerhouse. It is connected to an integrated transmission system.

Base Case Operating and Maintenance Conditions

- The project has a minimum flow release year round and is currently operated to produce maximum energy, on peak
- Unit is either on (generating) or disabled (forced or planned outage)
- The plant averages about 48 startups per unit per year: 12 for flow adjustments, 36 for startups after outages
- The annual O&M is $500,000 per year
- Components are inspected and repaired as needed
- Major overhauls are expected at routine intervals and conducted by outside vendors

Operation for A/S

Assume that given a competitive market, the operation will be modified to provide the following A/S products:

- Regulation/load following - the unit will provide generation that responds to moment-to-moment fluctuations in the grid, operating 10 hours a weekday, five days a week for the six "shoulder" months, for a total of 1300 hours a year. This operation varies the unit operation +/- 10% of capacity, requiring wicket gate adjustment.
- The unit does not supply reactive power in the synchronous condenser mode because it is not a priced ancillary product in the market. No mechanical or equipment provisions for synchronous condensing are installed.
- Spinning reserves - the plant will provide spinning reserve capacity, generating at minimum flow but in a ready mode for maximum capacity for six hours per weekday, five days a week for the same six shoulder months, for a total of 1300 hours per year. In this mode, the unit must be available at all times. During this six month period it is estimated that the unit will be called to supply reserve power up to four times per month, or a maximum of 24 additional ramp-ups/downs for short duration (several hour) periods.
- Supplemental reserves - the plant will provide supplemental reserve capacity—spinning but not synchronized with the grid for six hours per weekday, five days a week for the other six months for a total of 1300 hours per year. In this mode, the unit will synchronize and startup an additional two times per month, or 12 additional starts per year. The unit will also run in a sub-optimal wicket gate position.

Estimated Effects of Wear and Tear

If the plant operation is changed to provide A/S, what are the wear and tear costs associated with this changed condition?

To arrive at this cost we need to review the components of the plant that will see increased/decreased wear and tear and that will require additional maintenance to provide the service. This task is accomplished by speculating on which *components* might be affected by A/S operation and what *effects* the ancillary service operation will have on each component compared to the base case. For this generic example we consider the following components:

- Turbine runner and wicket gates
- Generator stator and rotor
- Circuit breaker

We assume that, given a base operating and maintenance plan, these components have an estimated remaining life after which time they will be replaced. However, if the unit is operated under A/S, several wear and tear effects can occur, including:

- Additional one-time maintenance costs to mitigate A/S operation might increase (cavitation repair to the runner occurs earlier within the remaining life).

- Periodic maintenance might increase because of increased starts. Instead of replacing contacts in the circuit breaker every three years, the contacts are replaced every two years.
- As a result of increased maintenance, the remaining useful life can be extended.

A summary of these effects for this generic example is described in Table 4-3.

Table 4-3
A/S Operation and Effects on Hydro Components - Generic Example

Component	Base Case Operations & Maintenance	A/S Product	Effect on Operations & Maintenance	Remaining Life
Turbine runner	Cavitation repair is expected in 5 years (mid-life year 17).	Regulation/load following		
		Supplemental reserves	Cavitation repair might be accelerated to year 15.	Assume a 5-year reduction
		Spinning reserves		
Wicket gates	Annual inspection and adjustment.	Regulation/load following	Variable operation and adjustment of the wicket gates will require additional adjustments on an annual basis.	Assume a 3-year reduction
		Supplemental reserves		
		Spinning reserves		
Generator stator and rotor	Annual inspection.	Regulation/load following	Inspection and repair might be accelerated to year 15 due to increased stresses.	Assume a 5-year reduction
		Supplemental reserves		
		Spinning reserves		
Circuit breaker	48 closings per year require that the contacts be replaced at 3-year increments at a cost of $3000. The total replacement of this piece of equipment in 18 years is estimated at $300,000.	Regulation/load following		
		Supplemental reserves	The A/S operation might increase the number of closures by 25% to 60 per year. This increases the replacement cycle to 2 years.	
		Spinning reserves	The A/S operation might increase the number of closures by 25% to 60 per year. This increases the replacement cycle to 2 years.	This increased service results in an estimated 2-year reduction in component life

Calculation of Wear and Tear Costs

Extending this analysis using the methodology presented in Table 4-2, Table 4-4 computes an incremental wear and tear cost of operating for A/S.

The steps in the methodology correspond to the columns in Table 4-4.

1. Compile the base case operating plan including output schedule and assumptions— assuming no A/S production. Estimate the “remaining life today” of each component.

   For the generic plant, the main components were all installed in 12 years ago. Assuming a 35-year life for the turbine runner, it has 23 years remaining life.

2. Compile the current “assumed maintenance under the base case,” that is, without A/S production.

   The generic plant has scheduled maintenance for periodic cavitation inspection and repair, adjustments of the wicket gates and seals, generator inspections, and inspection and contact replacement on the circuit breakers as part of the normal maintenance plan.

3. A) For each component that you consider will be affected by A/S operation, estimate the “component replacement cost” using the same technology as the installed component. Include replacement project labor and engineering.

   The estimated component replacement costs are shown in column 3A.

   B) Estimate the “new useful life” of the component assuming no A/S operation.

   Installing new components is assumed to renew the life of the unit by 30-35 years.

4. Forecast A/S production over the course of a year. Estimate the total amount of component activity for each product that causes wear and tear. For each component, identify and estimate the cost of additional:

   A) “One-time maintenance to mitigate A/S operation”

   B) “Periodic maintenance to mitigate A/S operation”

   Maintenance activities already budgeted in the base operating plan should not be counted again. Further, if A/S production would reduce the need for maintenance already assumed in the base operating plan, then the cost of that activity should be credited to A/S by including it as a negative cost here.

   For the generic plant, it is assumed that given the A/S operation case described above, the turbine runner can be repaired with a significantly better material to resist cavitation and the installation of a different cooling system will help mitigate thermal cycling stresses in the generator.

In addition, to mitigate A/S operation, increased inspections and adjustments are expected totaling $10,000 per year.

5. A) Estimate the "remaining useful life with maintenance" of the installed component, consistent with performing the maintenance projects in steps 4A and 4B.

   B) It might be useful to think of this as a "reduction in useful life" compared to the base case.

   Instead of 23 years under the base case operation, we believe the remaining life of the turbine runner is 18 years, a reduction of 5 years of useful life. The reduction in useful life should be similarly estimated for all the other components.

6. Next, estimate:

   A) "New life assuming A/S operation" for a new (replaced) component assuming that the A/S schedule is produced on a continuing basis and the incremental maintenance projects are continued over the new component's useful life.

   B) Again it might be useful to think of this in terms of a "reduction in useful life" compared to a new component life.

   Assuming the runner was replaced and operated for ancillary services, its new life might be 33 years instead of the previously assumed 35 years—a reduction of two years due to tougher service at partial load.

7. To compute wear and tear costs, compute depreciation rates for a new component with and without A/S production:

   A) "New depreciation for a new component" = Replacement cost/new useful life

   B) "Mitigated depreciation for new component with A/S"
   = Replacement cost/new life assuming A/S operation

   These two steps are just calculations of the previous steps. They relate the cost of a new replacement and new life to a new replacement operated under an A/S condition.

8. Summarize the maintenance costs by:

   A) Converting the cost of each assumed maintenance project to a "prorated annual maintenance" over the remaining useful life of the installed equipment. That is, one-time projects should be divided by "remaining useful life with maintenance."

   B) Computing "incremental annual maintenance under A/S case" by adding together the annual costs of all maintenance projects.

   These steps annualize the capital cost for a more costly cavitation repair material and generator cooling equipment installed to mitigate the wear and tear and then add incremental annual mitigation maintenance.

9. Compute total incremental wear and tear cost:

   Total wear and tear costs = "incremental annual maintenance"
   + ("mitigated depreciation" – "new depreciation")

As shown in Table 4-4, the total wear and tear for this generic example is approximately $28,000 per year.

Allocating the Wear and Tear to A/S Products

Extending the analysis of this generic example further, one would allocate the total wear and tear by component to each of the A/S products. Following the steps in Table 4-2, Table 4-5 continues this example.

10. Allocate total annual wear and tear cost to the A/S product classes according to how each product class was assumed to affect cost, as a percentage.

    For this generic example, the ancillary products are assumed to affect the unit components as shown on Table 4-5. Given this assumed allocation, the rules for each A/S are postulated as:

    – Regulation operation causes wear and tear as a function of:
      Runner wear (A) plus wicket gate wear and tear (B)

    – Spinning reserve operation causes wear and tear as a function of:
      Runner wear (A) plus generator wear (C) plus circuit breaker wear (D)

    – Supplemental reserve operation causes wear and tear as a function of:
      Generator wear (C) plus circuit breaker wear (D)

    – Reactive power is not supplied in this example

11. Compute activity cost rates for each product parameter by allocating the cost of each product class to the activity parameters and dividing by the assumed activity level.

    The resultant calculation, over the assumed events per year, results in a possible A/S pricing mechanism for this generic 15 MW hydro plant, taking into account the wear and tear component of operation.

    These costs as calculated are:

    $2.69 per MWh of regulation services provided

    $498 per ramp-up/ramp-down to provide spinning reserve

    $451 per startup/shutdown for supplemental reserve

These numeric results are merely an example of a methodology applied to one generic, but plausible plant. Numbers derived by this method will be ballpark figures. However, exercising the method on a number of real plants should lead to a better sense of the magnitude of the costs applicable to providing A/S.

Table 4-4
Generic Example of Wear and Tear Calculation of Hydro Units Operating for A/S

Methodology Step	1	2	3A	3B	4A	4B	5A	5B	6A	6B
Hydro component*	**Remaining life today 2000 (years)**	**Assumed maintenance under base case**	**Component replacement cost ($)**	**New useful life (years)**	**One-time maintenance to mitigate A/S operation ($)**	**Periodic maintenance to mitigate A/S operation ($/year)**	**Estimated remaining useful life with maintenance (years)**	**Reduction in useful life (years) (col 5A- col 1)**	**Estimated new life assuming A/S operation (years)**	**Reduction in useful life (years) (col 3B- col 6A)**
Turbine runner	23	cavitation repair	$2,000,000	35	$50,000	-	18	(5)	33	(2)
Wicket gates	18	adjustments	$1,000,000	30	-	$5000	15	(3)	28	(2)
Generator stator/rotor	23	inspection	$3,000,000	35	$60,000	$2000	18	(5)	33	(2)
Circuit breaker	18	replace contacts	$300,000	30	-	$3000	16	(2)	28	(2)
Air compressors	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total			**$6,300,000**		**$110,000**	**$10,000**				

Methodology Step	7A	7B	8A	8B	9
Hydro component*	**New depreciation for new component ($/year) (col 3A/col 3B)**	**Mitigated depreciation for new component with A/S ($/year) (col 3A/col 6A)**	**Prorated annual maintenance ($/year) (col 4A/5A)**	**Incremental annual maintenance under A/S case ($/year) (8A + 4B)**	**Estimated wear & tear cost ($/year) 8B+ (7B - 7A)**
Turbine runner	$57,143	$60,606	$2778	$2778	$6241
Wicket gates	$33,333	$35,714	$	$5000	$7381
Generator stator/rotor	$85,714	$90,909	$3333	$5333	$10,528
Circuit breaker	$10,000	$10,714	$	$3000	$3714
Air compressors	N/A	N/A	N/A	N/A	N/A
Total	**$186,190**	**$197,944**	**$6111**	**$16,111**	**$27,864**

Notes:
* Components assumed subject to wear and tear as a result of operation for A/S
N/A = not applicable

Table 4-5
Generic Example of Wear and Tear Allocated to A/S

Calculation of Wear and Tear (Repeated From Table 4-4)										
Methodology Step	**3A**	**3B**	**6A**	**6B**	**7A**	**7B**	**8B**	**9**		
Hydro component*	**Component replacement cost ($)**	**New useful life (years)**	**Estimated new life assuming A/S operation (years)**	**Reduction in useful life (years)**	**New depreciation for new component ($/year)**	**Mitigated depreciation for new component with A/S ($/year)**	**Incremental annual maintenance under A/S case ($/year)**	**Estimated wear & tear cost ($/year)**	**Hydro component**	
Turbine runner	$2,000,000	35	33	(2)	$57,143	$60,606	$2778	$6241	A	Note 1
Wicket gates	$1,000,000	30	28	(2)	$33,333	$35,714	$5000	$7381	B	Note 2
Generator stator/rotor	$3,000,000	35	33	(2)	$85,714	$90,909	$5333	$10,528	C	Note 3
Circuit breaker	$300,000	30	28	(2)	$10,000	$10,714	$3000	$3714	D	Note 4
Air compressors	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	E	Note 5
Total	**$6,300,000**				**$186,190**	**$197,944**	**$16,111**	**$27,864**		

Allocation of Wear and Tear to A/S										
Methodology Step						**10**	**11**			
Wear and tear caused by	**Runner (A)**	**Wicket gates (B)**	**Generator (C)**	**Circuit breaker (D)**	**Air compressors (E)**	**Estimated allocation rule to A/S products**	**Calculated wear and tear cost**	**Estimated number of events/year**	**$/Event**	**A/S pricing**
Regulation	50%	100%	0%	0%	N/A	50% A +100% B	$10,501	3900 MWh	$2.69	MWh regulation
Reactive power	N/A	0%	0%	0%	N/A	N/A	$0	hours/yr	N/A	per hour
Spinning reserve	50%	0%	75%	25%	N/A	50% A +75% C + 25% D	$11,945	24/year	$498	per ramp-up/down
Supplemental reserve	N/A	N/A	25%	75%	N/A	25% C + 75% D	$5418	12/year	$451	per startup
Total	**100%**	**100%**	**100%**	**100%**			**$27,864**			

Notes:
* Components assumed subject to wear and tear as a result of operation for A/S
N/A = not applicable
Note 1 Turbine runner is impacted by reserve service
Note 2 Regulation effects wicket gates
Note 3 Generator stator and rotor are impacted by increased thermal cycling
Note 4 Circuit breaker closure is increased to supply supplemental reserves
Note 5 Reactive power is not supplied

Hydro Unit Wear and Tear Methodology Application

This Tech Roundup focused on beginning to develop peer-unit cost data of wear and tear caused by operating for A/S. To obtain data, an exercise concept was conducted through a series of interviews. Participants, representing several different unit sizes as shown in Table 4-6, were interviewed. The operation and wear and tear methodology were developed by asking questions and collecting the data based on the understanding of the costs of a particular unit/plant. This method is similar to the Level I top-down method of calculating cycling wear and tear based on peer-unit average values, discussed in the EPRI fossil-fueled reports. Appendix A contains the details of the interview and presents the results of applying the methodology above to different hydro portfolios. Table 4-6 also shows the relevant parameters.

Table 4-6
Summary of Hydro Unit Wear and Tear Exercise

Participant	Hydro Portfolio	A/S Postulated	Hydro Components Analyzed
Generic plant example	1 unit, 15 MW	Regulation Spinning reserve Supplemental reserve	Turbine runner Wicket gates Generator Circuit breaker
Company A	1 unit, 8.5 MW 4 units, 16 MW 6 units, 110 MW	Reactive power Spinning reserve Supplemental reserve	Air compressors Generator and circuit breaker
Company B	26 units, 24–75 MW 11 units, 16–68 MW 4 units, 40–78 MW	Spinning reserve Supplemental reserve	Generator stator and rotor Circuit breaker

Exercises like these depict the types of analysis and data necessary to produce a hydro unit peer database. Ideally a larger participating cross section of hydro units and A/S would be analyzed with more complete understanding of the assumptions. Key data for further development would include the following:

- For step 3 - A more complete update of component replacement costs for various types and sizes of units, as well as reliable data on useful life.
- For step 4 - An understanding of the costs and methods for one-time maintenance projects that would mitigate wear and tear and provide a clearer definition of additional periodic maintenance costs.

- For step 5 - Understanding and development of empirical data based on statistics for estimating reduction in useful life. What are expected lives after replacement and under normal/base case operation?
- For step 6 - Development of empirical data based on statistics for estimating reduction in useful life. How do start-stop cycles reduce life? What about other components and effects?

5
RESEARCH ACTIVITIES

The preliminary results presented in this document allow for further discussion on the component wear and tear costs. Clearly more work is needed in this area and several groups are actively pursuing the quantification, including EPRI HAM. This section summarizes potential areas for further research and development identified in this report, the EPRI fossil program, and in hydro industry R&D forums.

Ongoing Research and Analysis

Hydro Resource Solutions and the Tennessee Valley Authority WaterView Program

To quantify wear and tear of hydro units operating for A/S in a rigorous manner, it has been suggested that the simultaneous logging and calculation of both the A/S production and operating characteristics (damage/life reduction) statistics be maintained over a fixed period of time.

To understand the operating characteristics, Hydro Resource Solutions LLC, a joint venture of Voith Siemens Hydro Power Generation and the Tennessee Valley Authority, have developed the WaterView® Maintenance Cost Module to track plant component operating statistics [18, 19].

The module utilizes cumulative damage theory, operating under the premise that component life is a function of the level of stress that a component endures over an interval of time and operating conditions. The basic concept is that a unit's life is diminished if it operates for a period of time under the effects of a stressor, such as vibration or cavitation at an operating condition (head or gate opening). The fraction of its life at these conditions is the ratio of the time it operates at these conditions to its expected life. Failure of a component occurs when all of these periods sum to one. Therefore, the remaining life of a component can be expressed as a percentage of time, given the sum of all the operating conditions.

Extending this to maintenance costs and assuming the maintenance cost at failure is known, the fraction of this total cost due to operation at a stressed condition can be calculated as a wear and tear cost.

The WaterView maintenance cost module consists of monitoring equipment and software, installed on various hydro unit components over a fixed operating period, to monitor in real time the stressors and responses. For example, a turbine guide bearing is monitored for wear over a fixed period and the algorithms in the cumulative damage theory software calculate the life used and the life remaining. The software also calculates the cost per startup or per operating hour, based on an assumed replacement cost.

Another example would be the monitoring of cavitation, as a function of vibration, again over a fixed period. The operation would be concurrently logged at different gate openings in order to determine wear and tear, life reduction points, and Most Efficient Load (MEL) conditions. In one cavitation monitoring application, it has been claimed that using WaterView led to an $80,000 maintenance cost savings during a 1.5-year period owing to avoidance of cavitation.

WaterView is to be installed at Chelan County Public Utility District’s 11-unit Rocky Reach and 18-unit Rock Island projects in the near future. It is expected that the data collected and analyses performed using this system will lead to a better understanding of the wear and tear effects of providing A/S.

Another area of study is incorporating operation and maintenance changes into plant functions. In a paper given at HydroInformatics, a discussion of knowledge management systems promoting paradigm shifts in managing the operation, maintenance, and environmental performance of hydroelectric power plants was put forth by Hydro Resource Solutions, LLC [20]. Essentially, moving the workforce from a conventional operation, maintenance, and environmental performance mode to a new paradigm required in a competitive industry requires new tools and education. Consider the following shifts in philosophy:

- Hydro operation relied on the use of the free fuel. Now hydro focuses on efficient operation and optimizing fuel usage.
- Hydro maintenance was conducted at fixed intervals. Now hydro utilizes operations-based maintenance systems and knowledge.
- Hydro environmental performance was reactive to pressures and requirements. Now hydro aims to deliver optimal environmental performance.

The framework for many hydro generation operations has undergone/is undergoing major changes—from the highest level of an organization’s management to the power plant floor. Even though a particular focus might be fairly narrow in the scheme of things, for example, this report’s focus on examining the relationship between A/S and wear and tear effects, understanding and working with this larger framework is key to gaining constructive results.

Bonneville Power Administration (BPA)

In recent analysis conducted by BPA, the costs associated with generation drops at the Grand Coulee Third Powerhouse were evaluated [21]. In order to maintain transmission system stability, a large generation drop (considered a unique form of A/S) can be provided and priced. In order to do this, the BPA can be requested to drop large increments of generation (up to 600 MW instantaneously). The study evaluated the costs in terms of two factors.

First, the desired generation drop service represents a significantly more severe service condition than the current baseload operation. Secondly, generation drop service entails more risk to the generating unit, if equipment and/or protective devices fail to operate properly. The approach taken analyzed equipment deterioration and risk of failure, routine operation and maintenance, and lost revenue, using historical operation and maintenance data and frequency of occurrence data. This data was then extended to the more severe duty case imposed by providing the generation drop service, as an incremental impact, expressed as a percentage change.

Several hydro components were analyzed, using historical data from the powerhouse and other hydroelectric units. This data included capital costs, operation and maintenance costs, and frequency of occurrence information for the turbine, generator, main 500 kV circuit breaker, the main power transformer, and 500 kV cable. The results, in terms of life reduction and incremental routine O&M, as shown in Table 5-1.

Table 5-1
Hydro Components Analysis

Component	% Life Reduction/Drop	Cost of Major Overhaul	Cost/Drop Life Reduction	Annual O&M Cost	Cost/Drop O&M
Turbine (rehab)	0.24%	$1,000,000	$2400	$450,000	$1080
Generator (rewind)	0.27%	$12,500,000	$34,290	$450,000	$1215
Circuit breaker (50% of replacement)	0.04%	$500,000	$200	$4,951	$2
Transformer (replacement)	0.015%	$5,706,900	$856	$57,069	$9
Cable (replacement)	0.055%	$2,850,000	$1.568	$213,469	$117

Reference: [21] Adapted from Table 1, 2

While the results of evaluating wear and tear during this unique A/S are not particularly relevant, the authors recognize that this same type analysis could price different duty cycles for other hydroelectric units.

In several recent papers, BPA described the results of unit modifications to permit operation as synchronous condensers at The Dalles and John Day projects on the lower Columbia River [22, 23, 24]. While these papers describe the retrofit, as they operate, statistics on operational costs could provide a model of other conversions to provide reactive power as a priced A/S for system stability.

Bureau of Reclamation

As mentioned in Section 2, the Bureau has begun investigations and developed a method for calculating production costs for ancillary generation services [13]. These algorithms and equations are for the unbundling of transmission services within the Western System Coordinating Council (WSCC). The concept presented in the paper assumes, “that there are no additional costs associated with providing A/S since none are currently provided.” Therefore, any additional costs incurred by future A/S production will be reflected in the future overall cost of operating and maintaining the facilities, and these costs can then be apportioned according to the total amount of products provide—a similar method taken in our simplistic exercises. While the application of this methodology to multiple Bureau plants is ongoing, the result will contribute to the understanding of wear and tear of hydro units.

Potential Areas for Wear and Tear Analysis and Research

In the development of this report, several potential areas for wear and tear data compilation, analysis, and research were identified. Table 5-2 summarizes potential research required to more fully understand wear and tear effects on hydro units. The topic areas are presented in no order of priority and are discussed below.

As the ancillary market develops, these topics will become of increasing interest to the hydropower industry to understand the effects of alternate operation on hydro units.

Research Areas Identified in This Report

In working through the methodology, there were several areas where further data compilation and discussion would serve to define the wear and tear costs. The availability of comprehensive data regarding the lives and costs of equipment and expected response to ancillary operation modes was limited. To understand maintenance for minimizing wear and tear, an understanding of the costs and methods for one-time maintenance projects that would mitigate wear and tear would be useful. In addition, a clearer definition of additional periodic maintenance costs and practices associated with improving life and responding to ancillary service demands would enhance the development of costs. A maintenance discussion workshop, roundtable, or forum could be convened to expand on Tables 1-2, 2-3, and 3-1 and to work through the methodology. A group discussion would begin the development of hydro peer unit wear and tear costs and ideas for mitigation measures, supported by input from manufacturers and consultants.

Research Activities Identified in EPRI Fossil Program

A/S Measurement Considerations

The EPRI report, *Measurement of Ancillary Services From Power Plants: Regulation, Load Following, and Black Start* [4], describes methodologies for measurements of A/S of regulation, load following, and black start. These methods speak to the need to certify or measure the quality of an A/S supplied as well as the quantity. The North American Electric Reliability Council (NERC) through its Interconnected Operations Services Implementation Task Force (IOSITF) draft Policy 10 addressed the need for A/S measurement. Individual Operating Authorities (OA) and Independent System Operators (ISO) also have specific criteria.

Practical and economical measurements for regulation and load following were accomplished that were the equivalent of certification testing for fossil-fueled unit, following this methodology:

1. Identify the load range (MW min to MW max) to be considered
2. Determine the unit's allowable loading and unloading rates (MW/min)
3. Determine maximum upward and downward acceleration (MW/min)
4. Determine OA/ ISO certification and performance requirements (NERC Policy 10)
5. Conduct the testing and evaluate unit's performance and compare to expected metrics
6. Obtain certification if successful; otherwise, evaluate and correct deficiencies

Performing the same measurements for hydro units for certification to ISOs as part of a premium pricing program for A/S might become a viable activity.

Black Start Capabilities

Black start service was discussed only in the EPRI report as a methodology, because an applicable test site was not located [4]. The black start methodology requires isolation of the unit in question together with the lines to be used to transmit the black start power—not a simple task because this requires a significant outage. A real black start must be performed followed by line energizing and loading. A summary of the test methodology is as follows:

1. Verify control communication, primary and alternate voice circuits
2. Perform basic starting test
3. Perform load energizing test
4. Perform load carrying test
5. Obtain certification if successful; otherwise evaluate and correct deficiencies

While it is recognized that hydro units can provide this service, it might be useful to develop procedures, identify candidate units, and perform tests. And as a consequence, be in a position to price the costs of wear and tear that might include deterioration of batteries and UPS systems. Furthermore, it would be useful to know unit capabilities, availability, and timing, particularly for hydro units in a deregulated market that are no longer a part of a transmission company.

Field Tests

The EPRI report, *Cost of Providing Ancillary Services for Power Plants: Regulation and Frequency Response* [5], recommended that field trials to determine actual wear as a result of operating in a regulation mode be conducted. The format included a period of operation in regulation (say for 6 hours), followed by an operation at a fixed load in the same conditions. During these periods for various unit types, several key variables would be measured such as number of adjustments, and minimum and maximum of gate operation. This information might provide further data for the quantification of wear and tear for regulation.

Similar field tests for reactive power during generation and synchronous condensing could be achieved if a protocol for testing standards and data collection could be developed.

For supplemental reserves, field tests building on the start-stop cycle costs could also be conducted for various sizes and types of hydro units.

Research Activities Identified in Hydro R&D Forums

In 1992, a hydro research and development forum was convened with over 80 representatives from the North American hydroelectric industry. The documentation of the forum addressed six broad topic areas for prospective research and development: operations, planning/analysis, environmental assessment and mitigation, hydromechanical issues, forecasting, and structure/hydraulics [25]. It is interesting to note that the dramatic changes in the electric industry relative to competition were barely anticipated. However, a few topics were generated related to A/S production as operational issues that required research. There is no doubt that if a forum were held today, A/S operation and maintenance would be one of the topics. Indeed, some research and data needs were noted that are applicable to wear and tear for A/S.

Since 1992, various groups have attacked these issues, not necessarily in the context of A/S operation but in understanding conventional hydro operation and maintenance. Further summary and extrapolation of these research and testing programs to the A/S focus might reap some benefits.

Table 5-2
Potential A/S Wear and Tear Research and Development Areas

Topic Area	Research Need	Potential Scope
Advanced bearing and actuator systems	To provide better and more durable materials and equipment to respond to minute-to-minute changes for load following and voltage control.	Expansion and supplemental work to that done by the Corps and Powertech Labs on bearing materials' response to minute fluctuations [26].
Advanced insulation systems for generators	To develop and test materials to reduce extended hydro generator outages due to stator winding failure or repair as a result of thermally induced stresses from cycling.	Review and testing of existing and new materials under anticipated service requirements [25].
Ancillary service measurement	The quality and quantity of A/S provided might require increased methods and instrumentation for measurement.	Preliminary work by EPRI has begun in this area [4].
Black start capability	The potential for hydro units to provide black start capability to the grid is recognized, but at this time not valued. Development of procedures to evaluate would assist owners in quantifying.	Preliminary work by EPRI has begun in this area [4].
Component replacement costs	A more complete update of component replacement costs for various types and sizes of units, as well as reliable data on useful life.	A survey, support by manufacturer input of component replacement costs.
Field tests: regulation	Observation of conditions and operations related to providing A/S might provide insight into wear and tear mechanisms.	Conducting field tests of operation with and without regulation while measuring variables for different units [4].
Mitigation maintenance for minimization of wear and tear	An understanding of the costs and methods for one-time maintenance projects that would mitigate wear and tear, and also provide a clearer definition of additional periodic maintenance costs and practices.	A maintenance discussion group developing costs and ideas for mitigation measures, supported by input from manufacturers and consultants. This would expand on Tables 1-2, 2-3, and 3-1.
Plant life assessment	Prediction of residual life of hydro unit system components from a wide database range would assist owners in evaluating plant life reductions as a result of wear and tear.	Scope could include the development of a hydro outage histogram, parametric modeling of life expectations of various components and accelerated life testing of components [25].
Understanding hydro unit start-stop cycles	For providing supplemental and replacement reserves, understanding the impacts of start-stop cycles could be examined in a rigorous manner with instrumentation and data collection over a range of hydro units.	An expansion of the IEEE work done in Sweden could be accomplished on North American hydro units [3].
Variable-speed hydro turbines	Modification of generating unit for constant frequency over a wide range of turbine speeds and heads could provide flexibility to provide ancillary services.	Review of potential applications to permit improved ancillary service operation could be conducted [14].
Vibration monitoring and interpretation	As a subset to understanding start-stop cycles, vibration monitoring and interpretation of results will increasingly play a part in predictive maintenance.	Scope could include a review of available instruments/techniques, presentation of operation parameters versus vibration data over time, and interpretation guidelines for users.

6
OBSERVATIONS AND CONCLUSIONS

Observations

EPRI-sponsored work focusing on the wear and tear of fossil-fueled facilities has led to some observations that are transferable to a hydro facilities context. In particular:

- A methodology for determining wear and tear effects and costs is preferable to a number. With a methodology, facility owners and operators can collect and apply data and make suitable adjustments so that the results reflect the project's circumstances.
- Data collection efforts will vary widely both in quality and amount of detail. Moreover, so-called "standard" terms for operation and "standard" cost categories can be expected to vary significantly among different organizations and facilities. To account for these variations, a methodology needs to aim to normalize data.
- Hydro unit owners and operators might resist sharing wear and tear related data owing to their views that:
  - The uniqueness of hydro installations and their operating circumstance make collection, analysis, and scaling of peer unit data inapplicable.
  - The large amount of data required for a bottom-up analysis (for example, even for the relatively simple exercises described in Section 4) might appear to be onerous.
  - Outside threats and competition make a "keep it to ourselves" approach preferable. Information sharing is too risky.

To address information-sharing concerns in a competitive environment, EPRI Technology Roundup reports aim to summarize topical information, including information from individual sources (without breaching confidentiality), and to promote *appropriate* information exchange. This appropriate information sharing enables individual organizations and individual hydro plants within organizations to enhance and improve their facilities and operations without compromising their competitive positions.

Conclusions

A/S are electricity products (for example, power for system regulation, reactive power, and operating reserves) that are increasingly being identified and marketed apart from the basic electricity commodities of energy (kWh and MWh) and power (kW and MW). Hydro facilities are inherently well suited and, in many cases, well situated to provide these valuable services. However, providing these services can increase the amounts of wear and tear on units.

A broad conclusion of this investigation is that while operation of hydro units to provide A/S can exacerbate hydro unit wear and tear, wear and tear costs are a relatively small cost of doing business in comparison to the value of the A/S that are delivered. This observation does not minimize the importance of properly accounting for both wear and tear effects and the costs involved. Facility managers need to know that they are giving suitable attention to avoiding wear and tear and to dealing with the likely consequences of increased wear and tear. As the value of A/S increase in the marketplace, the need for accurate information on the cost of providing service(s) will only increase.

Additional conclusions are:

- Hydro owners and operators would be prudent to account for wear and tear effects in establishing and forecasting maintenance, repair, and capital budgets.
- Facility upgrading might be needed in specific areas to support the provision of A/S.
- Several tools are available for evaluating wear and tear of individual units/facilities:
  - A check list approach as embodied in Tables 1-2, 2-3, and 3-1 that permits a facility review or audit, in light of prospective A/S requirements.
  - A methodology, as discussed in Section 4, that can provide general, overall estimates of operations, maintenance, and repair costs as allocated to A/S.
- Relevant investigations have estimated wear and tear effects and costs based on:
  - Equating a start-stop cycle a number of normal operating hour (10 hours per start-stop)
  - Assigning a dollar value to a start-stop cycle (from $130 to $450 per startup over a range of unit sizes ranging from 15 MW to 110 MW).
- The hydro unit wear and tear area might be worthy of further research. Available investigative methodologies extend well beyond what has been applied in the hydro context. EPRI's studies that focus on fossil-fueled facilities, for example, appear to be highly relevant from the perspective of the methodologies employed. Table 5-2 could form the basis for future research and development activities on this topic.

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A
HYDRO UNIT WEAR AND TEAR EXERCISE

The following interview outlines discussions with a utility participant following the methodology of Section 4. It is included here as an example exercise in applying the methodology to the unique parameters facing each wear and tear unit analysis. The exercise is presented in the following format:

- Hydro Portfolio Background
- Current (Base Case) Operating Conditions
- Operation for A/S
- Estimating the Effects of A/S on Hydro Unit Wear and Tear
- Wear and Tear Calculation and Allocation to A/S Products
- Other A/S Pricing

The following summarizes the results of the simplistic exercises of wear and tear. While these numbers are within expected ranges for wear and tear, they only indicate an order of magnitude. Insufficient estimation of this type has been accomplished to assign a high level of confidence to these results.

Table A-1
Wear and Tear Results

Participant	Hydro Portfolio	A/S Postulated	Wear and Tear Allocations	Hydro Components Analyzed
Generic plant*	1 unit, 15 MW	Regulation Reactive power Spinning reserve Supplemental reserve	\$2.69/MWh N/A \$498/ramp-up \$451/startup	Turbine runner Wicket gates Generator Circuit breaker
Company A	1 unit, 8.5 MW 4 units, 16 MW 6 units, 110 MW	Regulation Reactive power Spinning reserve Supplemental reserve	N/A \$2.20/hr \$246/ramp-up \$349/startup	Air compressors Generator Circuit breaker
Company B	26 units, 24–75 MW 11 units, 16–68 MW 4 units, 40–78 MW	Spinning reserve Supplemental reserve	\$220/ramp-up \$210/startup	Generator stator and rotor Circuit breaker

* Table 4-5
N/A – not analyzed

Company A - Hydro Portfolio Background

The portfolio of Company A includes hydro plants that total approximately 885 MW, producing an annual estimated generation of over 2050 GWh. The utility currently operates as a business unit generation and transmission supplier. Three average plants were surveyed for wear and tear qualitative background information and observations.

Table A-2
Company A Hydro Plants

Plant Name	Unit Type	Approx. Age (yr)	Normal Operation	# of Units	MW	Total MW
Plant A-1	Francis	35	AGC and synchronous condenser	1	8.5	8.5
Plant A-2	Francis	4 units – 70	AGC and synchronous condenser	4	16	64
Plant A-3	Kaplan	Unit 1: 32 Units 2-3: 32 Unit 4: 28 Unit 5: 29 Unit 6 20	AGC AGC and minimum flow Full load only Baseload and synchronous condenser Baseload and synchronous condenser	6	110	660

Current (Base Case) Operating Conditions

- All hydro units, when generating, operate to provide regulation and load following under Area Generation Control (AGC), except when a plant is at maximum capacity.
- Operating for regulation and load following has been a long-time operation practice. Segregating the costs between maintenance-related activities and regulation/load following is difficult. In order to do this, one needs to work backwards and determine what the cost would be if the unit were not providing this ancillary service with every kWh.
- Running a unit at minimum load is provided, not necessarily as spinning reserve, but to meet minimum river flows**.** Operating in this mode allows a unit to remain on, because it is perceived that a unit that has frequent shutdowns might have more wear. Running at some partial load in this case represents negative wear and tear—that is, wear and tear prevented by providing a service—analogous to driving a car simply to keep it running.
- Plant A-3 provides a minimum river flow of 2300 cfs, primarily during dry periods (July and August) and sometimes in the winter. Units 2 and 3 are usually used to provide this flow, although it might vary with load. A unit providing minimum flow can also provide AGC and therefore regulation services.

- Spinning reserve is combined with regulation/load following such that if 100 MW of reserve is required, two units might run at 50 MW (50% gate) instead of one unit at 100 MW. These units operating in this manner allow for regulation/load following and a reserve, if required, because they could be ramped up to full gate at any time. This situation is not necessarily called spinning reserve and how often it is done is not available.
- Units are either generating or spinning in air (synchronous condensing)—only Units 2 and 3 provide minimum flow.
- Units 5 and 6 do not run at minimum load due to vibration-related conditions and therefore experience only nominal cavitation.
- Reactive power supply by synchronous condensing is supplied at each of the stations as shown on Table A-1. Any unit in that mode can supply both spinning and supplemental reserves (ready in 10 minutes).
- The payment by the transmission company for synchronous condenser services is under study. Company A recognizes that this service is significant to the stability of the transmission system and is measurable. The hydro units have always run this way and have always provided service—but never priced the service. Data has been collected on frequency of occurrence, but not necessarily costs for running in the synchronous condenser mode.

Operation for A/S

Assuming that given a competitive market, operation will be modified to provide some additional A/S. To arrive at a wear and tear cost, data were collected from each of the three units considered the operating components of the plant that will see increased/decreased wear and tear and will require additional maintenance to provide the A/S. Table A-3 summarizes the base case operating conditions based on three years of operating data. An A/S operating case assumes the following:

- The units continue to provide reactive power, but the total costs will be accounted for in the methodology.
- Spinning reserve can also be provided from a unit operating at minimum flow—ramped up to provide maximum power. This condition was actually characterized as negative wear and tear. It was assumed that this ramp-up/ramp-down occurs six times per year from minimum flow to maximum flow.
- It was previously stated that spinning reserve is combined with regulation/load following such that if 100 MW of reserve is required, two units might run at 50 MW (50% gate) instead of one unit at 100 MW. These units operating in this manner allow for regulation/load following and a reserve, if required, because they could be ramped up to full gate at any time. This situation is not necessarily called spinning reserve and how often it is done is not available. For computation, it was assumed that 10 ramp-ups per year occur for a total of 500 hours.
- Both spinning and supplemental reserve can be provided from a unit in synchronous condenser mode, because the unit can be ready within 10 minutes. It was assumed that this occurs for 10 startups per year, for 40 hours total, for supplemental reserves.

The process of converting from generating to synchronous mode is as follows. The generator is normally generating and the load is backed off until the turbine wicket gates are at the synchronous speed, no-load condition (approximately 10 MW). The condense mode is then selected and the wicket gates start to close normally. At about 9% wicket gate opening, the main air valve is operated (by a gate limit switch) to admit air above the runner, pushing the water below the turbine blades. The wicket gates continue to close normally and the generator is motorized. The motorized generator requires approximately 1.6 MW of power to overcome losses (mostly windage) to maintain speed. The switch from synchronous condenser to generator is immediate and maximum load is provided within a few minutes.

Table A-3
Base Case Versus A/S Operating Parameters - Company A

Operating Mode	Plant	Forced and Planned Outages (hr)	Regulation and Voltage Control (hr)	Synchronous Condenser Reactive Power (hr)	Spinning Reserve (hr)	Supplemental Reserve 10-Minute Notice (hr)
Current base case	Plant A-1	362	3700	4430	None	267
	Plant A-2	236	7590	300	None	634
Operation B/C	Plant A-3 Units 1,2,3,4	N/A	N/A	N/A	N/A	N/A
	Plant A-3 Units 5-6	842	3120	4675	4675	123
A/S case	Plant A-1	Not analyzed	Not analyzed	Not analyzed	Not analyzed	Not analyzed
	Plant A-2	Not analyzed	Not analyzed	Not analyzed	Not analyzed	Not analyzed
Operation A/S	Plant A-3 Units 1,2,3,4	Not analyzed	Not analyzed	Not analyzed	Not analyzed	Not analyzed
	Plant A-3 Units 5-6	842	2400 hr at full load 500 hr at part load 220 hr at min flow	4675	500 hours 10 ramps/year 6 ramps per/year	40 hours 10 starts/year

Estimating the Effects of A/S on Hydro Unit Wear and Tear

Assume that given a competitive market, the operation will be modified to provide additional A/S. To arrive at this cost, the operating components of the plant were reviewed and it is speculated that some will see increased/decreased wear and tear and will require additional maintenance to provide the A/S.

The following speculates the components that might be affected by A/S operation and what effects the A/S operation will have on each component compared to the base case. Assuming that in the current operation, these components have a remaining life after which time they will be replaced. They also have an ongoing assumed maintenance plan that is conducted regularly. However, if the unit is operated for A/S, several impacts can occur, such as:

- Additional one-time maintenance costs to mitigate A/S operation might increase
- Periodic maintenance might increase
- The remaining useful life with this maintenance might be modified

Company A provided the qualitative comments, shown in Table A-4.

Generator Rotor/Stator

It was assumed for Plant A-3:

- A generator rewind costs an estimated $735,0000 and has a new life of 30–35 years under the current operation (simple depreciation of $22,000 per year)
- The increased cycling decreases life to 23 years (a 10-year reduction) the simple depreciation increases to $32,000 per year

For the unit to provide supplemental reserves, the unit will startup and synchronize with the grid and run briefly (<4 hours) then shut down an additional 10 times per year.

Circuit Breaker

The Plant A-3 unit circuit breakers are SF6 type:

- The average unit circuit breaker experiences five closures per year (two forced outages, three planned outages). An SF6 bottle lasts for seven years or 35 closures (assuming some leakage) and is replaced at $2670 ($380 per year).
- It is assumed that operation for ancillary services/supplemental reserves increases closures to five plus five more supplemental starts or 10 per year. Replacement will be increased to every three and a half years (or $763 per year) for this component.

Tailwater Suppression Air Compressors

Company A provided information on air compressor costs and usage for all plants, however only the Plant A-3 information is summarized here:

- The power consumption while in synchronous condenser mode is 1.6 MW continuously.
- The cost for initial blowdown of each unit to establish synchronous condenser is $4.66.
- The cost to maintain air during synchronous condensing is $0.20/hr.
- The maintenance costs on the compressors are $4666/year per unit.

- The operation and maintenance for the Plant A-3 synchronous air system average $9300 per year, including preventive, corrective, and routine maintenance.
- The air compressor system consists of three 350-psi compressors, two 2200-cf air receivers, one 100-psi air compressor, and associated piping valving and instrumentation. A 350-psi new air compressor replacement cost is $67,000 with a life expectancy of 20 years. A new 100-psi air compressor replacement is $16,700. Therefore a replacement of the system could be expected to amount to $217,000 or more.

Wear and Tear Calculation and Allocation to A/S Products

Table A-5 applies the methodology to the parameters of the base case and estimated A/S operating case. The results indicate a potential wear and tear cost speculation for these average hydro units—for the air compressor systems. The generator and circuit breaker components were estimated from other sources. Obviously a more rigorous analysis of each component and replacement cost and maintenance item is necessary to truly capture the total wear and tear cost. Other components, such as the turbine runner and wicket gates, were not analyzed.

Regarding allocation, the simplistic method used in step 11 (allocating costs to A/S products by some percentage) is only an estimate. The allocation assumed:

- Reactive Power is 100% allocated to Air Compressor (E) wear and tear.
- Spinning Reserve operation causes wear and tear as allocated:
  60% Generator wear (C) plus 40% circuit breaker wear (D)
- Supplemental Reserve operation causes wear and tear as allocated:
  40% Generator wear (C) plus 60% circuit breaker wear (D)

As a sensitivity analysis, alternate allocations, such as 75%/25% can be done to bracket the range.

Table A-4
A/S Operation and Effects on Hydro Components - Company A

Component	Base Case Operation & Maintenance	A/S Product	Effect on Operation and Maintenance
Turbine runner	Cavitation repair	Regulation/load following	Unknown—suspected none
		Supplemental reserves	Minimum flow unit if operated more could reduce wear and tear
		Spinning reserves/synchronous condenser	Operating synchronous condenser 70% of the time does not affect cavitation of runner Operating at 50% gate does—unknown
Wicket gates	Inspection and adjustment	Regulation/load following	Variable operation and adjustment of the wicket gates might require additional adjustments—unknown
		Supplemental reserves	Minimum flow unit wear
		Spinning reserves/synchronous condenser	Might require finer adjustments on WG, however records show the unit received no more maintenance than other units
Generator stator and rotor	Cavitation repair	Regulation/load following	Unknown—suspected none
		Supplemental reserves	None
		Spinning reserves/synchronous condenser	Will increase stresses on windings and exciter. Not easily measurable—but life reduction expected—unknown
Compressed air system - specifically for tailwater suppression	O&M cost	Regulation/load following	Variable operation and adjustment of the wicket gates might require additional adjustments. Unknown?
		Supplemental reserves	None
		Spinning reserves/synchronous condenser	Continual maintenance Replacement costs Might require finer adjustments on WG, however records show the unit received no more maintenance than other units

Table A-5
Wear and Tear Calculation and Allocation to A/S - Company A

Calculation of Wear and Tear										
Methodology Step	**3A**	**3B**	**6A**	**6B**	**7A**	**7B**	**8B**	**9**		
Hydro component*	**Component replacement cost ($)**	**New useful life (years)**	**Estimated new life assuming A/S operation (years)**	**Reduction in useful life (years)**	**New depreciation for new component ($/year)**	**Mitigated depreciation for new component with A/S ($/year)**	**Incremental annual maintenance under A/S case ($/year)**	**Estimated wear & tear cost ($/year)**	**Hydro component**	
Turbine runner	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	A	Note 2
Wicket gates	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	B	Note 2
Generator stator/rotor	$735,000	34	24	(10)	$21,940	$31,277	–	$9336	C	Note 3
Circuit breaker	Note 1	7	4	(3.5)	–	–	$763	$763	D	Note 4
Air compressors	$108,500	20	17	(3)	$ 5425	$6382	$9333	$10,290	E	Note 5
Total						**$37,659**	**$10,096**	**$20,390**		

Allocation of Wear and Tear to A/S										
Methodology Step						**10**	**11**			
Wear and tear caused by	**Runner (A)**	**Wicket gates (B)**	**Generator (C)**	**Circuit breaker (D)**	**Air compressors (E)**	**Estimated allocation rules to A/S products**	**Calculated wear and tear cost**	**Estimated number of events/year**	**$/Event**	**A/S pricing**
Regulation	N/A	N/A	0%	0%	0%	100% B	N/A	N/A	N/A	MWh regulation
Reactive power	N/A	N/A	0%	0%	100%	100% E	$10,290	4675 hr/year	$2.207	per hour
Spinning reserve	N/A	N/A	60%	40%	0%	60% C + 40% D	$5907	16 ramps/year	$246	per ramp-up/down
Supplemental reserve	N/A	N/A	40%	60%	0%	40% C + 60% D	$4192	10/year	$349	per startup
Total			**100%**	**100%**	**100%**		**$20,390**			

Notes:
* Components assumed subject to wear and tear as a result of operation for A/S
N/A = not applicable or available
Note 1 Circuit breaker replacement of SF6 canister is treated as a periodic maintenance item
Note 2 Wear and tear effects on turbine runners and wicket gates were not estimated
Note 3 Generator stator and rotor are impacted by increased thermal cycling
Note 4 Circuit breaker closure is increased to supply supplemental reserves
Note 5 Reactive power wear and tear assumes one-half of a $217,000 air compressor system replacement cost with a 20 year life

Company B - Hydro Portfolio Background

The portfolio of Company B hydro plants total approximately 1590 MW, represented by over 40 units ranging from 20–80 MW. The utility currently operates as an integrated generation and transmission supplier. Three regional river basin managers were surveyed for wear and tear qualitative background information and observations.

Table A-6
Company B Hydro Units

River Basin	Unit Types	Approx. Age (yr)	Normal Operation	# of Units	MW	Total MW
Basin A	Francis & propeller	35	Peaking and synchronous condenser	26	24–75 MW	961
Basin B	Francis & propeller	49	Peaking and synchronous condenser	11	16–68 MW	386
Basin C	Francis & propeller	35	Peaking and synchronous condenser	4	40–78 MW	243

Current (Base Case) Operating Conditions

- Normal operation for most of the units is maximum output, given storage. Some units are run-of-river and operate as such. Annual hydro generation averages approximately 4500 GWh at 30% plant capacity factor.
- An average unit in the portfolio is in the 30–78 MW range (represented by 30 units in the portfolio) and is a propeller machine with an average age of 40 years.
- An estimated 5% combined forced and planned outage rate yields approximately 8300 hours available per year.
- Most units typically operate 2800 hours generating both real and reactive power or in the synchronous condensing mode (motoring while spinning in air), provide reactive power for the remaining (approximately 5500) hours. At the upper limit, the typical unit (having a 0.9 power factor generator characteristic) has the potential to produce 2400 MVAR-hr per MW of capacity during the year while condensing.
- Currently, the average unit in the portfolio, when generating **does not** supply AGC regulation but does continuously provide voltage support.
- Currently the average unit in the portfolio **does** supply spinning and supplemental reserves.
- In plant terms, an average unit operates daily through the full stroke of gate operation, from speed, no-load to best gate as water permits for approximately 10 hours per weekday (split peaks: morning and evening during winter) and approximately six hours for the afternoon peak during summer. During all other weekday hours, except for minimum flow or high flow constraints, the units are then returned to the synchronous condenser mode for the balance of the week.

Operation for A/S

Assume that, given a competitive market, the operation of hydro units will be modified to provide some additional A/S. To arrive at this cost, the river basin managers reviewed the operating components of the plant that will see increased/decreased wear and tear and will require additional maintenance to provide the A/S. Table A-7 summarizes an alternative case.

Table A-7
Base Case Versus A/S Operating Parameters - Company B

Operating Mode	Forced and Planned Outages (hr)	Peaking and Voltage Control (hr)	Reactive Power (hr)	Spinning Reserve (hr)	Supplemental Reserve (hr)
Current base case	300	2800	5500	None	None
Operation B/C	5 circuit breaker closures	AGC (available at 2 plants)	Air compressor load	2 ramps per weekday = 520/year	None
A/S case	200	2800	5500	1250 (half capacity)	100 hours
Operation A/S	5 closures plus 5 more startups	AGC (economical to expand to other plants)	Air compressor load	5 per weekday = 1300/year	5 extra starts for 2 hours

Estimating the Effects of A/S on Hydro Unit Wear and Tear

The following speculates the components that might be affected by A/S operation and what effects the A/S operation will have on each component compared to the base case. Assuming that in the current operation, these components have a remaining life after which time they will be replaced. They also have an ongoing assumed maintenance plan that is conducted regularly. However, if the unit is operated for ancillary services, several impacts can occur, such as:

- Additional one-time maintenance costs to mitigate A/S operation might increase
- Periodic maintenance might increase
- The remaining useful life with this maintenance might be modified

The hydro unit managers provided the following qualitative comments.

Turbine Runner/Wicket Gates

None of the managers questioned indicated any expected wear and tear or incremental maintenance on the turbine runner.

However, to provide AGC in which moment-to-moment balances marginal demand with supply in the control area, the average unit potentially could experience up to 2800 hours of service duty per year. Such operation would multiply the ramping duty cycle as the unit varies operation. It is speculated this operation might increase wear on the servomotors, wicket gate seals, and governor pilot and main valves. (This component wear and tear was not estimated in Table A-9.)

Generator Rotor/Stator

The basin managers indicated that:

- The average unit generator stator and rotor under current operation incurs a two-time per day cycle. This operation results in a cycle frequency of (2 x 5 x 52) = 520/year. Assuming that operation for A/S increases cycling, the expected cycle frequency would increase to 25–50 cycles per weekday or 6500–13,000/year.
- This increased cycling is estimated to have a 10-year reduction in generator life. This number is based on units having a higher MVA duty (high reactive power duty while also generating real power). It is speculative, but could happen if reactive power from hydro units is deemed by system operators to be low cost. This would result in depending on the hydro units to supply reactive power for the system, when investment in static capacitance should have been added to the transmission system.
- A new average generator rewind could cost $800,000 and have a new life of 40 years under the current operation (simple depreciation of $20,000/year).
- The increased cycling could decrease life to 30 years (10-year reduction). The simple depreciation could increase to $26,666.

For the unit to provide supplemental reserve, the unit will startup and synchronize with the grid and run briefly (<2 hours), then shut down an additional five times per year.

Circuit Breaker

- The average unit circuit breaker experiences five closures per year (two forced outages, three planned outages). An SF6 bottle lasts for seven years or 35 closures (assuming some leakage) and is replaced at $4000, an annual cost of $571/year.
- Other costs are deemed not significant, partially because the managers had no means to quantify added costs from wear and tear on servomotors, wicket gate seals, and governor pilot and main valves.
- It is assumed that operation for ancillary services/supplemental reserves increases closures to five plus five more supplemental starts or 10/year. Replacement will be increased to every three and a half years (or $1143/year) from this component.

Wear and Tear Calculation and Allocation to A/S Products

Table A-9 applies the methodology to the parameters of the base case and estimated A/S operating case. The results indicate a potential wear and tear cost speculation for these average hydro units—for the generator and circuit breaker components. Obviously a more rigorous analysis of each component and replacement cost and maintenance item is necessary to truly capture the total wear and tear cost. Other components, such as the turbine runner and wicket gates were not analyzed. However, Company B has studied reactive power.

Regarding allocation, the simplistic method used in step 11 (allocating costs to ancillary service products by some percentage) is only an estimate. In Table A-9 the allocation assumed:

- Spinning Reserve operation causes wear and tear as allocated as follows:
  75% generator wear (C) plus 25% circuit breaker wear (D)
- Supplemental Reserve operation causes wear and tear as allocated as follows:
  25% generator wear (C) plus 75% circuit breaker wear (D)

Other A/S Pricing

A recent company internal review considered the operation of the hydro portfolio for reactive power support services:

- Estimated company provided station service costs for the portfolio were $4 million per year, for all station services.
- Operating and changeover to and from generation mode to reactive power mode is estimated to have an attendant station service power requirement of $2.5/kVA-yr.
- The preliminary conclusion supporting continuation of providing hydro reactive power was: "…the $4 million station service cost is justified since empirical results show hydro reactive power value exceeds station service costs less the cost of operating and maintenance required to shut down and restart the units each weekday, equating to 250 times per year. A low valuation of hydro units supplying reactive power would result in over reliance and usage of the units thereby shortening hydro life, and the deferral of investment in additions of the less expensive static capacitance to the transmission system."

Because it is given that the provision of reactive power by the hydro units has a value for voltage support on the integrated system, are the costs associated for providing this service being captured? The approximate company FERC filed tariffs for A/S are listed in Table A-8.

Table A-8
Company B A/S Pricing

Ancillary Product	Range of Pricing
AGC regulation & frequency support	$50.4/kW-yr
Reactive power	$1.32/kW-yr
Spinning reserve	$50.40/kW-yr
Supplemental reserve	$50.40/kW-yr

An approximate calculation of the cost of providing reactive power, assumes that 75% of the $4 million dollar cost of station service is for windage and heating losses (loading on air compressors also increases, but is not a significant part of the total cost). With this assumption, the cost is $3 million/8300 hr per year of reactive power provided plus the incremental O&M on the system.

Ignoring the O&M cost, the cost to provide reactive power is $360/hr reactive supplied.

Pricing the value of reactive power, assumes:

At $1.32/kW-yr x (1590/693) = $ 3.3/kVAR-yr at 8300 hr/year (generating and motoring)
= 0.4 mils/kVAR-hr provided.

This is a minimum cost figure because the generators likely will not average 0.9 power factor for all hours of operation. Therefore, reactive power worth $4 million offsets the costs to provide the A/S, which amounts to $3 million plus incremental O&M.

With regard to spinning and supplemental reserve, the control area (that is, ISO, RTO) likely will require different percentages of spinning and supplemental reserves. Hydro should be able to provide either spinning or supplemental reserves while providing reactive power, but no real power during off peak hours. However, there is a certain risk spinning reserves will be called upon, thus likely upsetting hydro's real power capability for the next day or longer. Each ISO/RTO will have to establish these operating requirements that could be different from region to region.

Table A-9
Wear and Tear Calculation and Allocation to A/S - Company B

Calculation of Wear and Tear										
Methodology Step	**3A**	**3B**	**6A**	**6B**	**7A**	**7B**	**8B**	**9**		
Hydro component*	**Component replacement cost ($)**	**New useful life (years)**	**Estimated new life assuming A/S operation (years)**	**Reduction in useful life (years)**	**New depreciation for new component ($/year)**	**Mitigated depreciation for new component with A/S ($/year)**	**Incremental annual maintenance under A/S case ($/year)**	**Estimated wear & tear cost ($/year)**	**Hydro component**	
Turbine runner	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	A	Note 2
Wicket gates	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	B	Note 2
Generator stator/rotor	$800,000	40	30	(10)	$20,000	$26,667	–	$6667	C	Note 3
Circuit breaker	Note 1	7	4	(3.5)	–	–	$1143	$1143	D	Note 4
Air compressors	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	E	Note 5
Total	**$800,000**				**$20,000**	**$26,667**	**$1143**	**$7810**		

Allocation of Wear and Tear to A/S										
Methodology Step						**10**	**11**			
Wear and tear caused by	**Runner (A)**	**Wicket gates (B)**	**Generator (C)**	**Circuit breaker (D)**	**Air compressors (E)**	**Estimated allocation rules to A/S products**	**Calculated wear and tear cost**	**Estimated number of events/year**	**$/Event**	**A/S pricing**
Regulation	N/A	N/A	0%	0%	0%	100% B	N/A	N/A	N/A	MWh regulation
Reactive power	N/A	N/A	0%	0%	100%	100% E	N/A	5800 hr/yr	N/A	per hour
Spinning reserve	N/A	N/A	75%	25%	0%	75% C + 25% D	$5286	150/year	$220	per ramp-up/down
Supplemental reserve	N/A	N/A	25%	75%	0%	25% C + 75% D	$2524	10/year	$210	per startup
Total			**100%**	**100%**	**100%**		**$7810**			

<u>Notes:</u>
* Components assumed subject to wear and tear as a result of operation for A/S
N/A = not applicable or available
Note 1 Circuit breaker replacement of SF6 canister is treated as a periodic maintenance item
Note 2 Wear and tear effects on turbine runners and wicket gates were not estimated
Note 3 Generator stator and rotor are impacted by increased thermal cycling
Note 4 Circuit breaker closure is increased to supply supplemental reserves
Note 5 Reactive power wear and tear was not analyzed

Targets:
Hydropower Operations

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