RECLAMATION

Managing Water in the West

Hydrogenerator Start / Stop Costs

U.S. Department of the Interior
Bureau of Reclamation
Technical Service Center

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Hydrogenerator Start / Stop Costs
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Executive Summary

It is becoming increasingly important to quantify the cost of ancillary services provided by Reclamation hydrogenerators to support integration of wind and solar energy into the power system. Two ancillary services – non-spinning and supplemental reserves – require starting and stopping generators on demand.

Starting and stopping generators more frequently potentially increases the cost of operation and maintenance. Various models have been developed in the hydro industry to measure the cost of starting and stopping. Assumptions vary widely in these models and a there is no consensus on what cost factors should be considered or on the costing methodology. A range of start/stop costs has emerged.

There is a need for a start/stop cost model suitable for use at Reclamation powerplants. The model developed herein includes cost factors of increased maintenance, accelerated equipment degradation, lost generation opportunity, lost water, and reduced efficiency. This research project uses this model to calculate start/stop costs for a pilot plant, resulting in a cost of approximately $274 to $411 per star/stop, depending on assumptions used. These figures should be used with caution, representing only one generating unit at one plant. However, these numbers are consistent in magnitude with other industry studies that use different assumptions and methods.

The model and methods developed in this research can be applied at other Reclamation powerplants. Experience at other plants would improve the model and broaden the base of data analyzed, better ensuring a reasonable start/stop cost.

This research includes a sensitivity analysis that identifies which cost factors are most important to overall start/stop costs, thus providing direction for future emphasis in refining costs.

Costing generator start/stops in Reclamation can be improved. This report describes areas of focus that may enhance the methods and tools, thus making the results more reliable and the process more user-friendly.

Scope

This study identifies salient and relevant cost factors for Reclamation hydrogenerator start/stops, derives a model for costing these factors, tests this model at a pilot plant (using field data) by calculating actual start/stop costs, and assesses which factors are most critical via a cost sensitivity analysis.

The goal is to define a methodology for estimating start/stop costs that can be used locally at other Reclamation powerplants. Because each plant is unique, it is not expected that a single start/stop cost will emerge that is applicable to all plants.

Costs of start/stops on pump-generators is not included, but the findings of this report may be applicable to such units.

This study identifies difficulties in obtaining data and/or applying the costing methodology and makes observations as to how to improve start/stop cost analysis.

The results of this study can be used to direct future research and as a template for start/stop cost analysis at other Reclamation plants.

Background

Measuring the costs of providing ancillary services delivered by hydroelectric plants has become increasingly important as hydro supports the growing integration of wind and solar energy into the bulk electrical power system (BES). Hydro generating units are well suited for supporting increased integration of these resources and Reclamation units provide this support for the western power grid. [3]

Ancillary services include regulation and frequency response, reactive power control, voltage control, and operating reserves.[10] Operating reserves include spinning, non-spinning, and replacement reserves.[1] Providing non-spinning and replacement reserves requires that generators be started and stopped upon demand.

When a unit is called upon to start from dead-stop (not spinning) in order to become available for service, there are impacts on staff, equipment, and water supply. These impacts have real effects on O&M practices and overall plant costs. As more starts are required these costs increase and should be accounted for. It may be appropriate for the increased costs to be incorporated into power rates charged to customers.

The fossil fuel generation industry has done extensive research into costing unit cycling. [8] But, there is very little reliable information that exists in the hydroelectric industry regarding start / stop costs. [3]. The available hydro studies approach the costing task in different ways and currently there is no industry standard for which cost factors should be included or how to derive the cost of each factor. Appendix A summarizes the approaches taken in the various studies and the associated resulting start/stop costs.

A methodology for identifying and quantifying increased start / stop costs in Reclamation is essential and is explored in this report. Existing documented strategies were researched and a Reclamation model was developed that incorporates ideas from these studies and reflects the unique concerns and business practices important to Reclamation facilities.

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[1] Spinning reserve is the capacity that can be provided by units already running. Non-spinning reserve can be provided within 10 minutes, while replacement reserve (also not spinning) can be provided within 1 hour. "Capacity" is assumed to be maximum unit capacity. [11]

Costing Strategies

Different strategies have been advocated by different elements of the hydro industry for costing start/stops. These strategies can be grouped into “top-down” and “bottom-up” categories.

Top-Down Strategy

The top-down strategy compares the overall cost of operating and maintaining a unit with high start/stop history to “peer unit averages” and assumes the cost difference is attributable to start/stop. [10]

This approach generally compares costs at a high level and those costs, unless carefully scrutinized, may include overhead and other costs that may not be directly related to generator operation. This method may also ignore some non-O&M (operation and maintenance) cost factors that could contribute to start/stop costs (e.g., efficiency and the value of water as a commodity).

The top-down approach has had some success in the fossil-fuel industry[2] but it requires a database with reliable data from a large number of generating units. Currently, there is no peer-unit database that can be used for similar hydro industry analysis. [10] Although developing such a database across the hydro industry (or even across a large organization like Reclamation) may be a worthwhile long-range goal, it does not solve the immediate problem of having a workable costing model.

Also, according to the fossil-fuel study, the top-down analysis may have inherent limitations unless a damage accumulation aspect is added. [8] In other words, the analysis must be augmented with some kind of equipment deterioration cost.

Bottom-Up Strategy

The bottom-up strategy attempts to identify all potential cost factors associated with an individual generating unit, quantify the associated costs, and roll them up to the unit level.

One advantage of the bottom-up strategy is that it identifies specific cost factors that can be modified locally, based on site conditions. It also has the advantage of producing a model that, while subjective, is immediately available to all facilities.

On the other hand, this approach requires access to a significant amount of O&M cost and equipment condition data. Accuracy depends on the availability and quality of the data. This

[2] The fossil fuel costing models include both top-down and bottom-up approaches and includes: establishing a pattern of historical high cycling, collecting and analyzing historical cost data, and comparing costs from actual operation to those for a base model. [8]

method also requires a certain amount of engineering judgment about the extent of equipment deterioration that is related to starting / stopping.

Strategy Summary

Both the top-down and bottom-up strategies are subjective and rely to some degree on comparisons between generating units (or plants) with higher start/stops to those with lower or "normal" start/stops (i.e., a "base case"). Both make the assumption that some or all of the increasing costs associated with high start/stop units are attributable to starting and stopping, and not to other causes. This assumption is subject to debate but must be made in order to develop a workable costing model.

This study investigates the bottom-up strategy because it permits detailed examination of all potentially important cost factors and because it results in a workable, portable model. The assumptions used and limitations of the model are noted.

Start / Stop Cost Model

This section identifies pertinent start /stop cost factors and derives a methodology for costing each factor.

In order for the model to be successful, it is assumed that a plant where it would be applied would have the following:

- One or more units experiencing an increased numbers of starts/stops as evidenced by operations records. The greater the increase, the more usable the model.
- Staff of experienced and trained O&M personnel dedicated to the facility (electricians, mechanics, engineers, management).
- A well-executed maintenance program that keeps equipment in good running condition.
- The maintenance program includes detailed equipment inspection and testing using measurable standards such as found in Reclamation FIST Volumes[3]
- A computerized maintenance management system (CMMS) for scheduling, tracking, and documenting maintenance work. In Reclamation, this is currently MAXIMO[4]

[3] Facilities Instructions, Standards, and Techniques. These manuals establish Reclamation's power program operation and maintenance requirements.
[4] An off-the-shelf maintenance, inventory, and property management software application that is part of CARMA, Reclamation's Capital Asset and Resource Management Application.

- A work order system that tracks the cost of labor, parts, materials, and service contracts needed to maintain equipment

- A financial tracking system which tracks O&M costs as well as capital expenditures. In Reclamation, this is FFS (Federal Financial System).

- Detailed O&M and financial records covering time periods sufficient for comparison.

Cost Factors

There are many potential cost factors that ***could*** contribute to start/stop costs. There is currently no industry consensus on which factors ***should*** be included, how the associated costs should be calculated, and which factors are most significant.

This study identifies the cost factors considered most important to Reclamation generators. The findings could be extended to pump-generators, adding costs for equipment specific to that type of unit.

Economic impacts of start/stop include:

- Increasing costs

- Decreasing revenues

Indicators of Increasing Costs	
Indicator	Metric
More Frequent / Costly Maintenance	• Longer actual PM staff hours to complete PM work orders (work more extensive than done historically) • More frequent PM work (shorter intervals as adjusted per condition monitoring or expert knowledge) • More parts and materials required to complete PM due to higher degradation • Increased number of CM (corrective maintenance) work orders due to equipment failure

More Frequent Equipment Replacement	• Higher capital expenditures for new equipment • Higher engineering costs (design, installation, testing, startup) • Higher direct labor costs (installation, testing, modification of systems to accommodate) • Higher procurement costs • Higher supervision and support costs

Indicators of Reduced Revenues	
Indicator	Metric

Reduced Generation
 	
• Lost-water energy (water used to start a unit is not being used to generate MW)
 	
• Reduced Availability
    • More frequent forced outages (due to equipment failure)
    • Longer planned outages (due to longer PM,CM duration)
    • More frequent planned outages (due to shortened PM intervals and increased CM)
    • Increased failure to start (due to wear and tear)
 	
• Lost Opportunity
    • Non-spinning reserve unit used for start/stop cannot be base loaded
    • Start/stop unit cannot take advantage of higher peak-time energy prices
 	
• Reduced efficiency (from prematurely
	• Reduced total MWH generated
	
	• Higher forced outage rate
	
	• Higher planned outage rate
	
	• Longer duration of outages (forced and planned)
	
	• Lower unit availability rate
	
	• Differential between start/stop and normal operation
	
	• Reduced total MWH generated

worn turbine runner)	• Measured / calculated loss of efficiency
Reduced Water Commodity Income	• Calculations showing the dollar value of lost water as a commodity.

The model developed herein investigates these costs and reduced revenues, which are identified as:

C_M	Incremental cost of maintenance caused by start/stops.
C_R	Incremental cost of equipment replacement / rehabilitation caused by start/stops
C_G	Reduced generation cost caused by start/stop, consisting of the following:
C_{WE}	Water energy cost
C_A	Availability cost
C_O	Opportunity cost
C_E	Efficiency cost
C_{WC}	Water commodity cost caused by start/stop
C_{SS}	Total start-stop cost, including all above components

Equipment Maintenance and Replacement

Equipment degradation affects both equipment maintenance and replacement / rehabilitation. Several theories exist in the industry on what equipment is – or may be - degraded by start / stop conditions.

Most equipment probably wears to some degree by starting and stopping, but wear occurs in continuous, on-line operation, as well. The percentage of wear due to start / stops is generally unknown and must be estimated.

It is useful to first consider what equipment may suffer wear and tear from start/stops, as outlined in Table 1.

Table 1 - Equipment Potentially Degraded by Start / Stopping

Component	Mechanism
Stator Winding	Voltage stresses, mechanical forces, thermal

	factors [6]
Rotor	Thermal cycling/vibration/inertia
Field Winding	Voltage stresses, thermal cycling/vibration/inertia
Generator Cooling System	Erosion/corrosion/electrical component thermal cycling, insulation deterioration
Generator Brakes	Friction/mechanical wear. Electrical component thermal cycling
Generator Buswork	Insulator deterioration. (Insulation thermal cycling, where cables are used)
Unit Circuit Breaker	Fatigue/mechanical wear/electrical arcing
Main GSU Transformer	Thermal cycling/insulation deterioration
Excitation System	Transformer thermal cycling/insulation deterioration; rectifier and cooling system electrical component thermal cycling; field breaker and field flashing breaker electrical and mechanical wear
Governor	Control and oil pump system mechanical/electrical wear
Servos / Wicket Gates	Mechanical wear/vibration/metal fatigue
Turbine Runner	Cavitation/fatigue/inertia/vibration
Water Passages	Corrosion/cavitation
Thrust and Guide Bearings	Mechanical wear/vibration; oil system mechanical/electrical wear
Turbine Bearing Cooling Water System	Erosion/corrosion/electrical component thermal cycling, insulation deterioration

Wearing Rings (Runner)	Mechanical wear/vibration
Control, Indication, and Auxiliary Systems	Mechanical and electrical wear

There is currently no consensus in the industry as to which of these components should be included in start/stop costing studies. Including them all is probably unnecessary and impractical. Some of the components are extremely durable, having such long service lives that any service life reduction due to start/stops is almost certainly minimal. In other cases, degradation is virtually immeasurable due to the restorative effects of preventive and corrective maintenance.

From the standpoint of increasing ***maintenance*** costs attributable to increased start/stops, all the components listed in Table 1were included in this study. When considering equipment ***replacement / rehabilitation*** costs, the list was reduced to make the process more manageable and less speculative. For replacement / rehabilitation, the study focused on a subset of components whose service lives may be reduced by start/stops. To that end, some components were not included in the equipment replacement part of the study, but may be added later by those wishing to explore their effects.

Generator Stator Winding

A CEATI report [7], developed by a working group representing twenty-one U.S. and international hydro utilities, tentatively identified degradation of the generator stator winding as a major area of concern with increased start/stops. Other start/stop studies also cite stator winding deterioration as a potential cost factor for start/stops. [13], [10], [14] The primary concern is that thermal cycling associated with start/stops could damage the insulation of stator coils. Electromagnetic and mechanical forces could also be damaging. However, a followup CEATI report [12] that relates winding insulation life expectancy to start/stop cycling concludes “there is little evidence that start/stop cycling significantly decreases the life of a winding.”

This subject is controversial and is a potential area for further industry discussion and research. This start/stop cost study initially does not include winding deterioration as an equipment replacement cost factor. However, in the sensitivity analysis section, the effect of potential winding deterioration is addressed, to determine if it has a significant effect on the cost factor.

Rotor

Rotors are extremely durable and replacement costs are not included in this study.[5]

Generator Cooling and Turbine Bearing Cooling Water Systems

[5] There is no Reclamation estimated service life available for this equipment.

Cooling systems – comprised of motors, starters, controls, valves, piping, and heat exchangers – will cycle on and off as the unit is started and stopped. However, components are replaced individually over time, to keep the system operational. Increasing maintenance costs are included in the study, but equipment replacement costs are not.

Generator Brakes

The brake system comprises shoes, cylinders, pumps, and piping which - although directly affected by start/stops - are repaired or replaced individually over time. Increasing maintenance costs are included in the study, but equipment replacement costs are not.

Generator Buswork

For this study, rigid copper buswork is assumed and replacement costs due to deterioration of insulators, is negligible. In plants using cable for buswork, this component may be included.

Main GSU Transformer

Operation of GSU (generator step-up) transformers varies by plant. Most Reclamation GSU transformers are kept energized to supply plant station-service AC power, even with the generators not online. As a result, they do not experience the drastic thermal cycling that would occur if energized and deenergized each time the generator was started/stopped. Even under normal, online operation, GSU transformer windings undergo a wide range of temperature variations as the load and ambient temperature vary. Therefore, this start/stop cost study does not include GSU transformer replacement costs as a cost factor, but it may be added at plants where transformer operation warrants.

Servos/Wicket Gates

Hydraulic servos and wicket gates operate more frequently as start/stops frequency increases. However, this equipment is very durable and can be kept in service indefinitely with proper maintenance. Therefore, replacement costs are not included in this study.

Water Passages

Water passages (penstock, scroll case) have extremely long service lives. This equipment is extremely durable, through many decades of use in a wide variety of operating conditions. While there may be some small amount of wear and tear on this equipment from starting and stopping, it is extremely difficult to quantify it and, given the long service life, the effect on start/stop cost will likely be very minimal. Therefore, replacement costs for water passages are not considered in this study.

Control and Auxiliary Systems

Most Reclamation units are started/stopped with automated systems, such as a computerized, supervisory control or a local-automatic start/stop controller. Synchronizing is typically done with a separate, solid-state or digital synchronizer or via a digital governor. There is little wear and tear on such systems and failure is extremely rare. Therefore, for this study, it will be assumed that there is no effect on unit control, protection, metering, and instrumentation systems from increased start/stop and replacement costs will not be included. The same is true of plant DC and AC systems.

Indirect Costs

Some industry studies attempt to capture indirect costs associated with start/stop. Indirect costs might include supervision, operation, procurement, warehousing, and engineering.[6] Whether indirect costs can be identified uniquely depends on local maintenance management business practices and use of the cost tracking system.

Reclamation's standard business practice is to capture as many costs as possible related to maintaining an equipment component by charging time and materials to the associated maintenance work order. For example, operator actions needed to facilitate an outage should be charged to the maintenance work order authorizing the maintenance work.[7]

Likewise, the cost of procuring parts and materials and performing engineering work related to the maintenance should be charged to the maintenance work order. This way, these overhead costs are captured and rolled into the cost of maintaining or replacing equipment. Where overhead costs are charged to "standing" work orders, not related to current maintenance, it is more difficult to track the overhead cost.

For purposes of this study, it is assumed that overhead costs, including operator costs, associated with maintenance are captured in work orders associated with the equipment. This study does not incorporate other types of overhead, such as general plant management or other costs not directly related to the generator.

Means of Calculating Costs of Each Factor

Calculating the cost of each cost factor is challenging. Some costs are more straightforward (e.g., water commodity, lost opportunity) while other costs are more difficult to quantify (e.g., equipment degradation, maintenance due to start/stop).

[6] Some studies classify costs such as lost opportunity as indirect costs, i.e., not directly impacting the cost of operating and maintaining the unit. This study addresses lost opportunity costs in another way.

[7] It is assumed that with an automated control system, the cost of operations NOT associated with a maintenance work order is negligible. If a non-automated plant must add operators or extend overtime to accomplish increased manual starts, these costs should be accounted for.

For some cost factors, it is necessary to compare costs before and after a unit begins increased start/stop operation, or compare to other similar (peer) units which are not started/stopped as often. This comparison results in "incremental" costs, assumed to be caused at least in part by increased start/stops.

This study identifies two time "windows" for comparing costs on a generator experiencing increased start stops: Window 1 is the period of time when the unit experiences "normal" start/stops (the base case); Window 2 is the period of time when the unit experiences increased start stops. Each window should be of sufficient length to allow for meaningful data collection and to average out anomalies in O&M that might occur in one year.

Maintenance Cost, C_M

This factor estimates the incremental cost of maintenance caused by start/stops.

Reclamation powerplants mostly use a time-based preventive maintenance (PM) program. In some cases, PM is triggered by number of operations (e.g., circuit breakers). Some condition-based maintenance is used to trigger PM, but this is not widespread in Reclamation.

Corrective maintenance (CM) is undertaken to correct unusual problems found during PM or by condition monitoring, or problems that have caused the equipment to fail, perhaps causing a forced unit outage. Correctly used, CM work orders capture all costs of corrective work, as opposed to "burying" the costs in PM or standing work orders. CM work orders can capture the "failure code" (failure mechanism) of the equipment, which may help determine if equipment degradation is related to start/stops.

Whether PM or CM, it is important for start/stop costing that all costs associated with the work be captured in the associated work order, including labor, parts, materials, and service contracts. Currently in Reclamation, MAXIMO labor rates are approximately equal to those found in the financial system and thus provide a fairly accurate picture of labor costs.

In this study, maintenance costs are retrieved from MAXIMO, rather than the financial system, FFS. This is because it is possible in MAXIMO to find costs by equipment component, by a generating unit, and by work orders (individually and by type: PM, CM). FFS does not track costs at this level of detail.

Work order costs may be affected by:

- Longer actual time (staff hours) to complete PM work orders (i.e., longer duration). Work more extensive than done historically on this equipment.

- More frequent PM work (shorter intervals as adjusted per condition monitoring or expert knowledge)

- More parts and materials required to complete PM

- Increased number of CM work orders

For example, permissive circuits for starting sometimes can be troublesome and CM work may increase with the number of starts which might cause these circuits to need additional attention. Likewise, as starts increase, CM costs may rise if maintenance personnel are called out to perform work outside of normal working hours (travel, overtime, etc). This is true for operations costs as well, if additional operator time is needed. These costs should be identified since they are directly related to start/stop.

It is important to assess maintenance work history over a significant period of time so that the data are meaningful. This may be difficult in some locations since maintenance history might be unavailable, incomplete, inaccurate, or simply difficult to retrieve. Still, the longer the time windows studied, the better the results.

When comparing costs from one time window to the other, it is important to compare the same group of components. The MAXIMO asset/location hierarchy should be studied carefully before retrieving data from the system so that cost comparisons are consistent.

Also, it is important to index annual maintenance costs for inflation. [8]

The general strategy to finding the Maintenance Cost per Start/Stop, $C_{M,}$ is first to determine the increase in total maintenance costs (PM + CM) for a generating unit that is being used for more start/stops than in the past OR that has a higher start/stop history than a peer unit in the same plant[9]. The windows of time studied should be of meaningful length, usually many years. Comparison should include all labor, parts, materials, and service contract costs. Note any costs not included in the work orders (e.g, operations, engineering, supervision, etc) and acquire or estimate and include those costs. Then, knowing the number of increased starts between the two windows of time, divide the number of increased starts into the cost of increased maintenance to determine the Maintenance Cost per Start/Stop, C_M.

A detailed protocol for calculating the Maintenance Cost per Start/Stop, C_M, can be found in Appendix B.

As discussed above, ***maintenance*** costs should be assessed for all the equipment components listed in Table 1, even though ***replacement*** costs for some of those components are not considered in this study.

[8] All costs must indexed for inflation and expressed in present value terms for meaningful comparison. This method seems less complex than the annualized cost method outlined by EPRI [10].

[9] Comparing to a peer unit in the same plant is not ideal. While this comparison better ensures that the peer unit is truly comparable in age and design, the comparison data is extremely limited and can be skewed by any anomaly (e.g., a forced outage). Ideally, comparison to peer units across the hydro industry would be better, but these data currently are not compiled.

Equipment Replacement Cost, C_R

This factor estimates the incremental cost of equipment replacement / rehabilitation caused by start/stops.

Starting, stopping, and continuous running all contribute to equipment degradation. Electrical and mechanical stresses eventually cause equipment to deteriorate and maintenance can only do so much to keep equipment in service. Replacement or major rehabilitation is inevitable and becomes a capital expense, a portion of which is likely attributable to start/stop.

Calculating incremental equipment replacement / rehabilitation costs begins with knowing the expected life of the equipment under a normal start/stop operating lifetime. Estimates of equipment service life in Reclamation is based on values established by the publication "Replacements – Units, Service Lives, Factors", jointly developed by the Western Area Power Administration (U.S. Department of Energy) and the Bureau of Reclamation, updated December 2005.[16] This document was developed using statistical methods with financial and replacement data gathered over several decades. The data were augmented with engineering and management expert knowledge of real-life plant equipment and costs.

Table 2 lists service lives from the Replacement book and estimated replacement costs for equipment considered in this study:

Table 2 – Service Lives[10] of Equipment Potentially Degraded by Start / Stopping

Component	Service Life (Years)	Replacement Cost ($)[11]
Field Winding	50	350,000
Unit Circuit Breaker	35	200,000
Excitation System	45	700,000
Governor	>50	500,000
Turbine Runner	50	1,500,000

[10] From Summary of Units of Property and Service Lives, July 1995 to December 2005, Table 2, Replacements book. Service lives specified are generalized, representing an average of many types of the same component. For example, power circuit breaker service life of 35 years results from analyzing oil, air, gas, and vacuum breakers and finding a reasonable average.

[11] In present value, 2012 dollars.

Thrust and guide bearings	>50	275,000
Wearing Rings, Runner	20	150,000

Once the service lives of equipment are established, degradation due to start/stops must be derived. Determining how much degradation is caused by start/stops vs. continuous operation is problematic. Given the very long service lives of most plant equipment, deterioration due to one start is probably negligible. However, the cumulative damaging effects of starting and stopping over many years should be accounted for, to the degree possible.

There are three possible approaches to quantifying the cost of equipment deterioration from start/stops.

Method 1:

In this method, total equipment replacement / rehabilitation costs would be compared over time periods (windows) with and without heavy start/stop demands (or between peer units with different start/stop histories). In theory, the cost differential is divided by the number of additional start/stops, resulting in an equipment replacement cost per start/stop, C_R.

Unfortunately, this method is impractical. The high durability of hydro plant equipment makes the time comparison windows so long as to become meaningless. For example, even with very long time windows of say 20 years, much equipment on a generating unit will not be replaced in either time window, much less in both. A similar difficulty arises when comparing peer units within a plant.

Therefore, comparing actual equipment replacement / rehabilitation costs using Method 1 becomes very speculative until a hydro industry database of peer units becomes available.

Method 2:

In this method, actual equipment deterioration from start/stops is measured and an associated cost calculated using the accepted service life and replacement costs.

Unfortunately, this method is also impractical. Technology does not exist to accurately measure degradation caused by start/stops.

Method 3:

In this method, a reasonable estimate is placed on the amount of deterioration to the equipment – i.e., loss of component service life – attributable to start/stops. This life loss is used to calculate the associated cost using the accepted service life and replacement costs.

To the degree possible, engineering data are used to validate the estimate, but the method relies heavily on expert judgment.

Variations of this method are used in several industry start/stop cost studies and, although convenient, it does have some weaknesses. It requires access to meaningful engineering data and it is subjective in that there are many ways to interpret the data.

This study advocates the use of Method 3 that, despite its drawbacks, is the only practical approach. Experts should be consulted to assign reasonable estimates of degradation attributable to start/stops. Experts should use their professional judgment and the following tools to make their determinations:

- Diagnostic testing data (on-line and off-line) (See Appendix C)
- Measurements performed during PM and CM (See Appendix C)
- hydroAMP[12]equipment condition indicators and condition indices (See Appendix C)
- Equipment failure codes, as tracked in MAXIMO (See Appendix C)
- On-line machine condition monitoring (MCM) data (See Appendix C)
- Overall maintenance and equipment replacement history, as documented in MAXIMO and the federal financial system, FFS

This study also includes a comparison of Reclamation deterioration estimates to an approach documented in several other hydro industry start/stop studies. These studies cite an EPRI[13] report [10] which cites a previous EPRI study and even earlier research that estimates that each start has an equipment aging effect of 10 hours of routine operation. This number is debatable and should be used with caution. (See Appendix D).

The 10-hour per start/stop loss-of-life figure is used for comparison in this study because it is so widely used in other studies. However, the loss-of life estimates used in this study to arrive at start/stop costs were generated independently of the EPRI figure.

Method 3 also requires the user assume an average annual number of start/stops that are "normal" over the expected service life of the equipment. Reclamation (and the hydro industry) estimate service lives in years, not in number of start/stop cycles. Therefore, assumptions are made in this study to demonstrate the method, but effort is needed to better establish normal start/stop duty for hydro equipment.

A detailed protocol for finding the Equipment Replacement Cost per Start/Stop, $C_{R,}$ via Method 3, including an example, can be found in Appendix B.

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[12] hydroAMP was developed by Reclamation, Hydro-Québec, the US Army Corps of Engineers, and Bonneville Power Administration as a means to evaluate and document the condition of hydropower equipment and facilities in order to support business decision-making.

[13] Electric Power Research Institute

Reduced Generation Cost, C_G

More frequent start/stops incur a reduced-generation cost. A generator not used for start/stops likely generates more revenue than one used more for start/stops. The cost should be determined and included in the total start/stop cost.

Reduced generation costs include:

- Water Energy Cost, C_{WE}
- Availability Cost, C_A
- Opportunity Cost, C_O
- Efficiency Cost, C_E

Water Energy Cost, C_{WE}

This factor estimates the energy value of water used to start a generator.

Water used to start a unit is not being used to generate energy. The volume of water lost to start/stops may become significant as units are started and stopped more often and the associated cost should be calculated.

The time from unit start to synchronism may be several minutes. This includes the time it takes to break away the unit from stop and accelerate it to rated speed. Once at rated speed (speed-no-load), it takes additional time to synchronize the unit to the power system. In addition, water used in ramping is not used as efficiently as when the unit is operating at load. The water "lost" during these steps cannot be used for generation.

The general approach to finding the water energy cost is to calculate the amount of energy that could have been produced with the water that was used for starting and ramping and then find the associated cost in dollars.[14]

A detailed protocol for finding the water energy cost per start/stop, C_{WE} , can be found in Appendix B.

Availability Cost, C_A

This factor estimates the energy revenue lost to increased outages attributable to start/stops.

As the unit is used more for start/stops, the availability may be reduced by:

[14] This cost must be considered with Water Commodity costs to prevent "double counting". Whether or not both costs are included depends on whether water is delivered to end-users via the generator.

- More frequent forced outages, as equipment fails sooner
- Longer planned outages as more PM and CM is needed on worn equipment
- More frequent planned outages because PM intervals are shortened to address wear and tear

Note that the reduced availability cost is separate from the lost opportunity cost. The latter is based on losses incurred due to an overall change in the way the unit is being operated – more starts vs "normal" operation. Reduced availability costs are incurred because the unit is out of service more often, or for longer periods, to accomplish maintenance, replacements, or rehabilitation necessitated by start/stop wear and tear.

The general strategy to finding the availability cost is first to determine the difference in the outage time between the normal start/stop time window and the high-start/stop window (or between peer units with different start/stop demands). Then, find the cost of this time in lost generation. Assume the differential is due to increased start/stops and calculate the availability cost of each start/stop. Adjust the result as needed, using expert judgment to account for other factors that might cause outages.

A detailed protocol for finding the availability cost per start/stop, C_A , can be found in Appendix B.

Opportunity Cost, C_O

This factor estimates the energy revenue lost to the unit being used for start/stop operation in lieu of continuous generation.

Units available for start/stops are not spinning and not on line. Such units cannot generate at any level and certainly cannot take advantage of higher peak-time energy prices. This creates a lost opportunity cost.

On the other hand, hydro plants generally have low plant factors[15] (e.g., 20 - 25% is not unusual and 34% is a reasonable expectation), are not operated online for other reasons, and would not be available for generation, even if not designated as non-spinning or replacement reserve. For example, sufficient water may not be available to generate or water-release constraints for environmental and recreation reasons may take priority.[16] And, of course, water contracts must be observed. All these constraints have higher priority than generation at Reclamation facilities.[6]

Therefore, when determining the lost opportunity cost per start/stop, assumptions must be made about how the unit might have been used for generation, given the operating constraints on the powerplant. In developing the costing model, it is assumed the start/stop unit could be used for generation at maximum load were it not being used for start/stop operation. This is the

[15] 100 x Ratio of average power generated to rated capacity.
[16] Minimum/maximum stream flow, reservoir level restrictions, mandatory releases, flood control.

assumption used in other start/stop costing models, but the average generation load could also be used.

The general strategy to finding the opportunity cost is first to find the difference in the dollar value of generation[17] between the normal start/stop time window and the high-start/stop window. Then, find the cost of this time in lost revenue. Assume the differential is due to increased start/stops and calculate the cost of each start/stop.

A detailed protocol for finding the opportunity cost per start/stop, $C_{O,}$ can be found in Appendix B.

Efficiency Cost, C_E

This factor estimates the energy cost of lost efficiency attributable to start/stops.

The principal cause of reduced efficiency is a worn turbine runner. As a runner wears by cavitation, efficiency is lost – it takes more water to generate a given amount of electrical energy. This "lost" water has associated energy and commodity costs. The amount of reduced efficiency caused by start/stops should be estimated.

Cavitation likely occurs to varying degrees while starting, when ramping up and down, when running at load, and when in rough-running zones, where damage is greater than at other loading levels.[6]

The degree of cavitation taking place at each stage of the starting and running cycle is unknown. It is very difficult to measure cavitation in real-time and difficult to know how much cavitation is taking place on the runner surface, as opposed to harmless cavitation taking place in the water itself. Existing technologies are not able to make these measurements. Reclamation has begun some research in this area, but no conclusions have yet been reached.

Measuring the degree of efficiency loss over time is theoretically straightforward. When a turbine is new, efficiency is measured to confirm that design and fabrication meet specification requirements. Later, measurements could be made and compared to the original to quantify the degree and rate of degradation (probably non-linear).

However, these latter efficiency measurements are rarely, if ever, done. Efficiency testing is time-consuming and fairly expensive. To date, there has been little justification to make these measurements. Therefore, the actual percentage loss of efficiency over the turbine runner service life is unknown, as is the degree of efficiency loss attributable to start/stops.

Thus, the efficiency loss must be estimated. For consistency throughout the model, the estimated percentage loss of efficiency attributable to start/stops is the same percentage used in calculating

[17] Net generation gives a better estimate of the value of the energy than gross generation since some energy is used in-house.

the turbine runner replacement start/stop costs in the Equipment Replacement cost section of this report.

Since efficiency loss equates to "lost" water, the general methodology for finding the start/stop reduced efficiency cost is to calculate the volume of water lost to reduced efficiency, estimate the portion of this volume attributable to start/stops, and calculate the associated energy and commodity costs for each start/stop.

A detailed protocol for finding the efficiency cost can be found in Appendix B.

It should be noted that turbine design methods and materials are evolving and the amount of cavitation damage in the future may be considerably less than in the past. Modern computer models make it possible to design runners more accurately and stainless steel, which is more resistant to cavitation, is replacing cast steel. According to EPRI "…stainless steel runners resist cavitation – often to the point that regular repairs are minimal and, at times, no longer necessary." [9] Turbine efficiency losses caused by cavitation are probably very low and, over time, improved turbines could reduce the loss essentially to zero.

Total Reduced Generation Cost, C_G

The total reduced generation cost per start/stop, C_G , for a generating unit can be calculated as:

$$C_G = C_{WE} + C_A + C_O + C_E$$

Water Commodity Cost, C_{WC}

This factor estimates the commodity cost (value) of water used for start/stops.

The primary purpose of many Reclamation hydroelectric projects is to deliver water for irrigation, municipal, and industrial use. Hydropower is a byproduct. Water stored in the reservoir can be sold as a commodity to users and, over time, water sales help repay the initial investment and operating costs of the project.

The water commodity cost, C_{WC}, of water used in start/stops should be calculated, where applicable. Factors such as the time of year and minimum water release requirements play a part in determining if this cost is applicable. If the water released during start/stops is in fact sold as a commodity at that time, then the lost commodity cost is zero, i.e., the value of the water as a commodity was not lost.[18]

[18] This cost must be considered with Water Energy costs to prevent "double counting". Whether or not both costs are included depends on whether water is delivered to end-users via the generator.

The general strategy to finding the water commodity cost is to determine the amount of water used in start/stops, including that lost to inefficiency in ramping up and down, and find the commodity value of this water.

A detailed protocol for finding the water commodity cost per start/stop, C_{WC}, can be found in Appendix B.

Total Cost Per Start/Stop, C_{SS}

The total start / stop cost C_{SS} for a generating unit can be calculated as:

$$C_{SS} = C_M + C_R + C_G + C_{WC}$$

where: C_M = Maintenance Cost per Start/Stop
C_R = Equipment Replacement Cost per Start/Stop
C_G = Reduced Generation Cost per Start/Stop
C_{WC} = Water Commodity Cost per Start/Stop

Input Data Requirements

As the protocols show, the model requires the user to input many types of data. The input data requirements are summarized in Appendix E.

Case Study Using Costing Model

The model described above for calculating start/stop costs is theoretical and must be tested with data from a pilot plant. Testing reveals whether the model is user-friendly, is feasible given the data available, and produces reasonable results. Testing in the "real world" indicates where data are not available and points the way to future work that could improve the model itself and the existing field tools used to collect data and estimate start/stop impacts.

Careful selection of the pilot powerplant is crucial to testing and the following criteria were considered:

- Plant where one (or more) generating unit has experienced increased start/stop demands
- Multi-unit plant having peer units of similar design and age, for comparison
- Availability and quality of maintenance data in MAXIMO
- Availability and quality of financial data in MAXIMO and FFS
- Availability of turbine efficiency measurement data
- Water has a commodity value
- Receptivity of local management to start/stop cost study

The pilot plant selected was Flaming Gorge Powerplant, part of the Colorado River Storage Project (CRSP) of the Upper Colorado Region. Flaming Gorge is located on the Green River in northeastern Utah and has shown a significant increase in start/stops in the last several years.

Details of the Flaming Gorge case study are included in Appendix F and are summarized here:

Flaming Gorge Unit 1 Start/Stop Cost Factor	 Start/Stop Cost ($)
Maintenance Cost, C_M	8.00
Equipment Replacement Cost, C_R	145.00*
Reduced Generation Cost, C_G • Water Energy Cost, C_{WE} ($10) • Availability Cost, C_A ($36) • Opportunity Cost, C_O ($0) • Efficiency Cost, C_E ($3)	49.00
Water Commodity Cost, C_{WC}	72.00
Total Cost per Start/Stop, C_{SS}	$274*

*These costs do not include generator stator winding start/stop degradation effects. The next section of the report addresses this potential cost.

Sensitivity Analysis

There are many assumptions and estimates involved in costing each factor – assumptions and estimates that are subjective and debatable. Therefore, it is important to do a cost sensitivity analysis to measure how each cost factor impacts the total cost per start/stop.

A sensitivity analysis clarifies which factors are most important and, therefore, worth more time and effort to analyze and refine.

This analysis calculates and compares “betas” for each factor or component. For purposes of this analysis**, beta is the percent change in the start/stop cost for a 100% change in the cost of the factor or component**. The results show which factors are most impactful.

Analysis 1:

This analysis calculates the effects of different assumptions regarding stator winding degradation, using Flaming Gorge data. The results are represented in Tables FGSA-1A, 1B, and 1C.

Table FGSA-1A assumes that there is no degradation to the stator winding (i.e., no replacement cost) associated with start/stops. This is consistent with some research which concludes that start/stops have no measureable effect on winding life. [12]

Table FGSA-1B assumes that there is some degradation to the stator winding attributable to start/stops. In this case, rewedging the stator at 20 years for $150,000 is assumed. This is based on the Flaming Gorge experience in 2011, although the start/stop effect on those wedges is speculative.

Table FGSA-1C assumes that there is sufficient degradation to the stator winding from start/stops to have some effect on a rewind (no core replacement). This is consistent with other publications which conclude that start/stops have significant effects on winding life. [7], [10], [13], [14]

One set of calculations in each table uses the start/stop percent loss of life figures developed by site personnel. For comparison, the tables also show results for equipment degradation using EPRI 10-hours-per-start loss-of-life estimate.

These three tables illustrate the variations in start/stop costs for the different assumptions and show betas for all equipment components and for each cost factor.

Table FGSA-1D summarizes Flaming Gorge Unit 1 cost factor sensitivity for the three scenarios considered above.

Table FGSA-1A
Generator Start/Stop Cost Sensitivity Analysis
With No Stator Winding Degradation

Service-Life Av Ann # Starts	35
Window 1 Av Ann # Starts	35
Window 2 Av Ann # Starts	113
N_{SS}	78
Plant Factor	31.40%

EPRI Start/Stop Replacement % = (Service-Life Av Ann # Norm Starts X 10 hrs/ss) / (8760 hrs/yr x Plant Factor) = (35 x 10) / (8760 x .314) = 13%

				EPRI 10-Hr-per-Start				**Flaming Gorge**			
Component	**Service Life (Yrs)**	**Total Replacement Cost ($)**	**Annual Replacement Cost ($)**	**Start/Stop Replacement % per EPRI**	**Annual Start/Stop Cost per EPRI ($)**	**Replacement Cost per Start/Stop per EPRI ($)**	**EPRI BETA**	**Start/Stop Replacement % (Reclam)**	**Annual Start/Stop Cost per FG ($)**	**Replacement Cost per Start/Stop per FG ($)**	**Flaming Gorge BETA**
Stator Winding (Not Included)	25	$0.00	$0.00	13	$0.00	$0.00	0	4	$0.00	$0.00	0
Field Winding	50	$350,000.00	$7,000.00	13	$910.00	$26.00	6	4	$280.00	$8.00	3
Unit Circuit Breaker	35	$200,000.00	$5,714.29	13	$742.86	$21.22	5	70	$4,000.00	$114.29	42
Excitation System	45	$700,000.00	$15,555.56	13	$2,022.22	$57.78	13	1	$155.56	$4.44	2
Governor	50	$500,000.00	$10,000.00	13	$1,300.00	$37.14	9	2	$200.00	$5.71	2
Turbine Runner	50	$1,500,000.00	$30,000.00	13	$3,900.00	$111.43	26	1	$300.00	$8.57	3
Thrust & Guide Brgs	50	$275,000.00	$5,500.00	13	$715.00	$20.43	5	1	$55.00	$1.57	1
Seal Rings	20	$150,000.00	$7,500.00	13	$975.00	$27.86	6	1	$75.00	$2.14	1
Equipment Replacement, C_R						$301.86	70			$144.73	53
	COST ($)										
Maintenance C_M	$8.00						2				3
Water Energy C_{WE}	$10.00						2				4
Availability C_A	$36.00						8				13
Opportunity C_O	$0.00						0				0
Efficiency C_E	$3.00						1				1
Water Commodity C_W	$72.00						17				26
All Factors							100				100
COST PER START/STOP						**$430.86**				**$273.73**	

Table FGSA-1B
Generator Start/Stop Cost Sensitivity Analysis
With Stator Winding Rewedging

Service-Life Av Ann # Starts	35
Window 1 Av Ann # Starts	35
Window 2 Av Ann # Starts	113
N_{SS}	78
Plant Factor	31.40%

EPRI Start/Stop Replacement % = (Service-Life Av Ann # Norm Starts X 10 hrs/ss) / (8760 hrs/yr x Plant Factor) = (35 x 10) / (8760 x .314) = 13%

				EPRI 10-Hr-per-Start				Flaming Gorge			
Component	**Service Life (Yrs)**	**Total Replacement Cost ($)**	**Annual Replacement Cost ($)**	**Start/Stop Replacement % per EPRI**	**Annual Start/Stop Cost per EPRI ($)**	**Replacement Cost per Start/Stop per EPRI ($)**	**EPRI BETA**	**Start/Stop Replacement % (Reclam)**	**Annual Start/Stop Cost per FG ($)**	**Replacement Cost per Start/Stop per FG ($)**	**Flaming Gorge BETA**
Stator Winding (Rewedge)	20	$150,000.00	$7,500.00	13	$975.00	$27.86	6	4	$300.00	$8.57	3
Field Winding	50	$350,000.00	$7,000.00	13	$910.00	$26.00	6	4	$280.00	$8.00	3
Unit Circuit Breaker	35	$200,000.00	$5,714.29	13	$742.86	$21.22	5	70	$4,000.00	$114.29	40
Excitation System	45	$700,000.00	$15,555.56	13	$2,022.22	$57.78	13	1	$155.56	$4.44	2
Governor	50	$500,000.00	$10,000.00	13	$1,300.00	$37.14	8	2	$200.00	$5.71	2
Turbine Runner	50	$1,500,000.00	$30,000.00	13	$3,900.00	$111.43	24	1	$300.00	$8.57	3
Thrust & Guide Brgs	50	$275,000.00	$5,500.00	13	$715.00	$20.43	4	1	$55.00	$1.57	1
Seal Rings	20	$150,000.00	$7,500.00	13	$975.00	$27.86	6	1	$75.00	$2.14	1
Equipment Replacement, C_R						$329.72	72			$153.30	54
	COST ($)										
Maintenance C_M	$8.00						2				3
Water Energy C_{WE}	$10.00						2				4
Availability C_A	$36.00						8				13
Opportunity C_O	$0.00						0				0
Efficiency C_E	$3.00						1				1
Water Commodity C_{WC}	$72.00						16				26
All Factors							100				100
COST PER START/STOP						**$458.72**				**$282.30**	

Table FGSA-1C
Generator Start/Stop Cost Sensitivity Analysis
With Stator Rewind

Service-Life Av Ann # Starts	35
Window 1 Av Ann # Starts	35
Window 2 Av Ann # Starts	113
N_{SS}	78
Plant Factor	31.40%

EPRI Start/Stop Replacement % = (Service-Life Av Ann # Norm Starts X 10 hrs/ss) / (8760 hrs/yr x Plant Factor) = (35 x 10) / (8760 x .314) = 13%

				EPRI 10-Hr-per-Start				Flaming Gorge			
Component	**Service Life (Yrs)**	**Total Replacement Cost ($)**	**Annual Replacement Cost ($)**	**Start/Stop Replacement % per EPRI**	**Annual Start/Stop Cost per EPRI ($)**	**Replacement Cost per Start/Stop per EPRI ($)**	**EPRI BETA**	**Start/Stop Replacement % (Reclam)**	**Annual Start/Stop Cost per FG ($)**	**Replacement Cost per Start/Stop per FG ($)**	**Flaming Gorge BETA**
Stator Winding (Rewind)	25	$3,000,000.00	$120,000.00	13	$15,600.00	$445.71	51	4	$4,800.00	$137.14	33
Field Winding	50	$350,000.00	$7,000.00	13	$910.00	$26.00	3	4	$280.00	$8.00	2
Unit Circuit Breaker	35	$200,000.00	$5,714.29	13	$742.86	$21.22	2	70	$4,000.00	$114.29	28
Excitation System	45	$700,000.00	$15,555.56	13	$2,022.22	$57.78	7	1	$155.56	$4.44	1
Governor	50	$500,000.00	$10,000.00	13	$1,300.00	$37.14	4	2	$200.00	$5.71	1
Turbine Runner	50	$1,500,000.00	$30,000.00	13	$3,900.00	$111.43	13	1	$300.00	$8.57	2
Thrust & Guide Brgs	50	$275,000.00	$5,500.00	13	$715.00	$20.43	2	1	$55.00	$1.57	0
Seal Rings	20	$150,000.00	$7,500.00	13	$975.00	$27.86	3	1	$75.00	$2.14	1
Equipment Replacement, C_R						$747.57	85			$281.87	69
	COST ($)										
Maintenance C_M	$8.00						1				2
Water Energy C_{WE}	$10.00						1				2
Availability C_A	$36.00						4				9
Opportunity C_O	$0.00						0				0
Efficiency C_E	$3.00						0				1
Water Commodity C_{WC}	$72.00						8				18
All Factors							100				100
COST PER START/STOP						**$876.57**				**$410.87**	

Table FGSA-1D Summary of Flaming Gorge Cost Factor Sensitivity (For Scenarios Summarized in Tables FGSA-1A, 1B, & 1C)			
	Beta (% Change in Total Cost Resulting from 100% Change in Factor/Component Cost)		
Factor/ Component	**No Stator Degradation**	**Stator Rewedge**	**Stator Rewind**
Stator Winding	0	3	33
Field Winding	3	3	2
Unit Circuit Brkr	42	40	28
Excitation Sys	2	2	1
Governor	2	2	1
Turbine Runner	3	3	2
Thrust & Gde Brgs	1	1	0
Seal Rings	1	1	1
Equip Repl, C_R	53	54	69
Maintenance, C_M	3	3	2
Water Energy, C_{WE}	4	4	2
Availability, C_A	13	13	9
Opportunity, C_O	0	1	0
Efficiency, C_E	1	1	1
Wtr Commod, C_{WC}	26	26	18
Total All Factors	100	100	100
Start/Stop Cost	$274	$282	$411

The analysis shows that equipment replacement / rehabilitation costs represent the majority (53 to 69%) of the total start/stop cost. The stator winding (when a rewind is included) and unit circuit breaker costs are the most significant of all components considered.

The water commodity cost is significant, ranging from 18% to 26% of the total start/stop cost.

The majority of factors and components have relatively low betas. The start/stop cost is not very sensitive to large variations in the costs of these low-beta components / factors. Even if the assumptions used and/or data collected were inaccurate, the effect of these factors on total start/stop cost is still minimal.

Analysis 2:

This analysis calculates the effects of different assumptions regarding opportunity costs.

The start/stop cost calculations and Sensitivity Analysis 1 use the opportunity cost, C_O, of \$0, based on the Flaming Gorge Unit 1 data showing that there was no decrease in generation in the high start/stop window. Thus, the beta calculations were not applicable to this cost.

To test the effect of Flaming Gorge Unit 1 being operated in such a way as to <u>reduce</u> net generation opportunity, assume a reduction of 20% from the 84.08 MWH average generation in 2000-2005. At a power rate of \$27.70 per MWH, the resulting C_O is \$5.97. This is relatively small (1 to 2%), of the total start/stop costs calculated in any of the three scenarios analyzed above. Therefore, opportunity cost does not appear to be a major start/stop cost factor for most reasonable scenarios.

Analysis 3:

This analysis calculates the effects of different assumptions regarding the number of starts assumed for Window 1 (normal) and Window 2 (increased). This analysis is applied to the Flaming Gorge data used in Analysis 1, including an opportunity cost of \$0.

Flaming Gorge Unit 1 starting history:

Average Annual Starts 2000-2005: 35
Average Annual Starts 2006-2011: 113
Average Annual Increase in Starts: 78 (225%)

Although the percent increase was significant, the absolute numbers of starts is relatively low. Units at some plants would be started much more often. To test the effect of a change in the number of starts, assume :

Average Annual Starts Window 1: 150
Average Annual Starts Window 2: 300
Average Annual Increase in Starts: 150 (100%)

The cost and sensitivity analyses under these assumptions are summarized in Table FGSA-3.

Table FGSA-3
Summary of Cost Factor Sensitivity
Assumed Higher Number of Window 1 & 2 Starts

	Beta		
Factor/Component	**No Stator Degradation**	**Stator Rewedge**	**Stator Rewind**
Stator Winding	0	3	35
Field Winding	3	3	2
Unit Circuit Bkr	45	44	29
Excitation Sys	2	2	1
Governor	2	2	1
Turbine Runner	3	3	2
Thrust & Gde Brgs	1	1	0
Seal Rings	1	1	1
Equip Repl, C_R	57	58	72
Maintenance, C_M	2	2	1
Water Energy, C_{WE}	4	4	3
Availability, C_A	8	7	5
Opportunity, C_O	0	0	0
Efficiency, C_E	1	1	1
Wtr Commod, C_{WC}	28	28	18

Total All Factors	100	100	100
Start/Stop Cost	$253	$260	$390

Significantly changing the average annual number of starts for Windows 1 & 2 has a modest effect (5 to 8% reduction) on costs per start/stop. Note that increasing the number of starts affects maintenance, availability, opportunity, and efficiency costs, but not replacement, water energy, and water commodity costs.

Analysis 4:

This analysis calculates the effects of different assumptions regarding the service-life average annual number of starts.

The service-life average annual number of starts affects only the equipment replacement cost, C_R. The number used for the Flaming Gorge start/stop cost analysis and for Analyses 1 – 3 was 35, implying that over the service life of the unit components the average number of starts is 35 per year.

Whether this assumed service-life average annual number of starts is realistic is unknown at this time. Equipment service lives are estimated in years, not in number of starts. Additional research is needed to quantify the average annual number of starts that might be expected over equipment life, because it is crucial to calculating the equipment replacement cost.

To analyze the effect of this variable, assume that the service-life average annual number of starts is 70, instead of 35. This analysis is applied to the Flaming Gorge data used in Analysis 1. The results are summarized in Table FGSA-4.

Table FGSA-4
Summary of Cost Factor Sensitivity
Assumed Service-Life Average Annual # of Starts = 70

	Beta		
Factor/Component	**No Stator Degradation**	**Stator Rewedge**	**Stator Rewind**
Stator Winding	0	2	25
Field Winding	2	2	1

Unit Circuit Bkr	28	28	21
Excitation Sys	1	1	1
Governor	1	1	1
Turbine Runner	2	2	2
Thrust & Gde Brgs	0	0	0
Seal Rings	1	1	0
Equip Repl, C_R	36	37	52
Maintenance, C_M	4	4	3
Water Energy, C_{WE}	5	5	4
Availability, C_A	18	18	13
Opportunity, C_O	0	0	0
Efficiency, C_E	1	1	1
Wtr Commod, C_{WC}	36	35	27
Total All Factors	100	100	100
Start/Stop Cost	$201	$206	$270

Significantly changing the service-life average annual number of starts has a major effect (27 to 34% reduction) on costs per start/stop. Therefore, it is important to establish a generally-accepted average annual number of starts over equipment service lives in order to stabilize the equipment replacement cost, $C_{R,}$ and start stop cost, C_{SS}.

Effect of EPRI Loss-of-Life Estimate:

Because the EPRI 10-hour-per-start loss-of-life estimate is used in many other start/stop cost analyses, it was included in all study calculations for comparison purposes. Table FGSA-5 summarizes the comparison.

Table FGSA-5
Summary of Start/Stop Costs
Comparison Flaming Gorge to EPRI

		Start/Stop Cost ($)		
		No Stat Deg	Rewedge	Rewind
W1: 35 W2: 113 N_{SS}: 78 Svc Life: 35 (Analysis 1)	Flaming Gorge	274	282	411
	EPRI	431	459	877
W1: 150 W2: 300 N_{SS}: 150 Svc Life: 35 (Analysis 3)	Flaming Gorge	253	260	390
	EPRI	410	432	856
W1: 35 W2: 113 N_{SS}: 78 Svc Life: 70 (Analysis 4)	Flaming Gorge	201	206	270
	EPRI	419	446	848

The EPRI start/stop costs are consistently and consistently higher (57 to 119%) than the Flaming Gorge costs for Analyses 1 and 3, where the service-life average annual number of starts is 35. When this number is raised to 70 (Analysis 4), the EPRI costs are 108 to 214% higher than the Flaming Gorge costs. This is not surprising since the EPRI loss-of-life method overestimates the effect of start/stops on replacement costs.

This sensitivity analysis information can help focus future start/stop costing efforts into areas with highest benefit.

Conclusions and Improvements

The calculated start/stop cost range of $274 - $411 is reasonable and is comparable to costs found in other studies. However, it must be noted that the costs calculated here are based on one generating unit at one plant and may not be representative of all plants.

The model developed in this study for costing Reclamation generator start/stops addresses all potential cost factors. This model, like all others in the hydro industry, makes many assumptions and estimates. Even though these assumptions and estimates are subject to debate, the model provides a reasonable framework for calculating start/stop costs at a powerplant. Given that a hydro industry database does not exist for broad comparison, the model may be the best available at this time, for Reclamation purposes.

From the model development, case study at Flaming Gorge, and the sensitivity analysis, it can be concluded that:

- All the cost factors assessed in this study deserve examination as to their effects on start/stop costs and it is clear that some cost factors have more impact than others.

- Even though increasing maintenance costs would seem an important start/stop cost, the data do not substantiate this. Maintenance expenditures often are driven by budgets and staffing levels. Also, the effects of start/stops on maintenance may not be known for many years after start/stops increase and thus may not be captured in the cost analysis. This cost factor should remain in the model and be evaluated over time and at other sites.

- Equipment replacement costs, as affected by start/stop deterioration, appear to be the most significant of all cost factors (53 to 69% of the start/stop cost). The subjectivity used in their calculation cannot be avoided, given current MCM technology and lack of an industry database for comparison.

- Improving the tools (Table ER-2) used for estimating start/stop equipment replacement costs would assist field forces in making and documenting valid estimates. Specifically,

    - Review the tests and measurements standards and procedures for compatibility with data collection needed for start/stop costing.

    - Ensure that hydroAMP tools address the needs of start/stop costing.

    - Make the failure code hierarchy in MAXIMO consistent with the NERC[19] GADS (Generating Availability Data System) Cause Codes. This would improve the ability to compare with other utilities.

    - Investigate easily-accessible MCM technologies that might improve assessment of actual equipment condition.

- Developing default values for start/stop percent replacement costs for each component would add consistency to equipment replacement and start/stop costs across Reclamation. The values could be recommended, and modified as needed at each site, when justified.

- Assumptions about stator winding degradation attributable to start/stop are important to the cost calculations. Consensus on the degree of degradation effects (if any) would narrow the range of start/stop costs.

[19] North American Electric Reliability Corporation.

- Including more equipment components in the equipment replacement/rehabilitation cost calculations would allow for a more comprehensive analysis.

- Availability and water commodity costs are not insignificant and should be included in the model until evaluated at other facilities.

- The net generation method shows that opportunity costs do not appear to be significant in comparison to other start/stop factors. A net revenue approach may result in measurable opportunity costs by showing that starting more often shifts generation from peak to non-peak periods. Acquiring net revenue values for the model and experience at other sites could verify such an approach.

- Further research may confirm that efficiency costs from turbine deterioration are so insignificant that they could be dropped from the model.

- Significantly changing the average annual number of starts for study Windows 1 & 2 has a modest effect on costs per start/stop. Therefore, the model is reasonably stable for this variable and it could be used at other locations having different operating histories.

- Changing the service-life average annual number of starts has a major effect on costs per start/stop. Establishing a generally-accepted average annual number of starts over equipment service lives would stabilize the model for this variable.

- Applying the model at other Reclamation powerplants and pump/generating plants would help identify limitations, improve user-friendliness, and establish a better-documented range of start/stop costs.

- Automating the model (e.g., via a spreadsheet) would allow field forces to input the required data and all calculations would be performed by the spreadsheet. This would make the model more accessible and reduce calculation errors.

- Developing a weighting system (similar to hydroAMP) for each cost component, taking into account confidence in the collected data and costing methodology, might improve the model.

- Continuing to work with organizations like EPRI, CEATI, and other hydro utilities to improve databases and methods of tracking, calculating, and comparing relevant start/stop costs would improve Reclamation’s understanding of start/stop costs and improve the costing model.

Summary

As it becomes increasingly important to quantify the cost of supplying ancillary services such non-spinning and supplemental reserves, a start/stop cost model that can be used at Reclamation plants is needed.

The model developed in this study incorporates ideas in the various hydro industry models and studies in existence. Cost factors of interest to Reclamation also have been added, for a more complete picture of start/stop costs.

By necessity, many assumptions and estimates have been used. The model is valuable, even using other assumptions and estimates.

The Flaming Gorge case study shows a range of start/stop costs ($274 - $411) dependent on what generator components are included. These figures are unique to one unit at one plant and extrapolation to other plants should be avoided. However, they are in the same order of magnitude found in other hydro plant start/stop cost studies.

This study found that some cost factors are more significant than others and that the relative importance of factors may be site-dependent.

The model developed in this study can be applied at other Reclamation powerplants. Experience at other plants would improve the model and broaden the base of data analyzed, better ensuring a reasonable start/stop cost.

Costing generator start/stops in Reclamation can be improved. Several areas of focus have been outlined that may enhance the methods and tools, thus making the results more reliable and the process more user-friendly.

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Appendices

APPENDIX A

Comparison of Start/Stop Costing Methodologies and Related Studies
March 25, 2012

Study	S/S Cost[20]	C_M	C_R	C_G				C_{WC}	Strategy / Notes
				C_{WE}	C_A	C_O	C_E		
Reclamation – Generator Start/Stop Costs (2012) (This study)	$ 274* $282** $411***	Y	Y	Y	Y	Y	Y	Y	One 50.65MW unit only, using actual plant data and bottom-up methodology. Uses EPRI 10-hour per start loss for comparison. *No stator winding degradation **Includes stator winding rewedge ***Includes stator rewind (not core)
CEATI T022700-0315 (2006) [7]	2010 equivalent: $212 - $638 for 100MW unit	Y	Y	N	N	N	N	N	Maintenance, repair, and cost data for 45 Norwegian and 10 North American plants 1999-2001 analyzed for failures, wear, and labor. Stator core and winding, rotor, bearings, auxiliary equipment, main closing valve assumed to be 75% of start/stop costs. Turbine and governor assumed to be 15-20% of start/stop costs. Assumes properly sized excitation, cooling water, GSU xfmr, and unit breaker do not contribute to start/stop costs. Primarily focusses on stator winding insulation deterioration.

[20] Indexed with the Consumer Price Index (CPI) from the Bureau of Labor Statistics.

EPRI TR-113584-V4 (2001) [10]	$451 2011 equivalent: $573	Y	Y	N?	N?	N	N	N	Theoretical model with hypothetical generating unit. Equipment degradation from start/stops estimated. Cites 10-hour per start/stop loss of life from previous EPRI study and earlier research into winding degradation. Outlines Top Down and Bottom Up strategies.
IEEE paper by Nilsson & Sjelvgren (1997) [14]	Varies from $70-$270 for 20-110MW to $130-$330 small to P/G (1997) 2011 equivalent: $98 - $378 (20-110MW) $182-$462 (small to P/G)	Y	Y	Y	Y	N	N	N	Recognizes energy costs of water lost during start and outages. Focusses most on costs due to stator winding degradation, wear and tear on mechanical equipment, and control system malfunction.
Reclamation - Mt. Elbert (2009) [13]	$518 (2009) 2011 equivalent: $543	Y	Y	N	N	Y	Y	Y	Pump-generating 100MW unit. Includes stator winding degradation.
CDWR Castaic (2003) [4]	$375 (2001) 2011 equivalent: $458	Y	Y	Y	N	N	N	N	7-Unit P/G plant.

CEATI T072700-0349 (2009) [5]	NA	NA	NA	NA	NA	NA	NA	NA	Analyzed North American operating statistics (e.g., GADS) to determine impacts of increased start/stops on reliability. Concludes that “there is no clear evidence that higher starts per year of service are the primary cause of higher unreliability in the hydro fleets.” Argues for reliability-centered and predictive maintenance, early warning systems, and improved training to improve reliability. Recommends better failure reporting to improve reliability analysis.
CEATI T102700-0369 (Undated Draft) [12]	NA	NA	NA	NA	NA	NA	NA	NA	Examines several studies and concludes that “start/stop cycling is most likely a minor, if not negligible, loss of life factor” for windings. Recommends that monitoring and periodic repair can extend winding life.
Reclamation – Calculating Production Costs for A/S (1999) [11]	NA	Y	Y	N	Y	N	N	N	Generic model developed; does not calculate cost of each start/stop. Allocates total production costs (from financial data) to various ancillary services based on availability of those services at the bus using historical operating data. Demonstrates method to calculate total costs of providing non-spinning and supplemental reserves.
EPRI 1001507 (2001) [8]	NA	Y	Y	NA	Y	NA	NA	NA	Report on <u>thermal</u> plant damage due to cycling. Quantifies relationship between increased starting and equipment degradation.

C_M – Maintenance Cost (includes operation and overhead)
C_R – Equipment Replacement / Rehabilitation Cost
C_G – Reduced Generation Cost
C_{WE} – Lost-Water Energy Cost

C_A – Reduced Availability Cost
C_O – Lost Opportunity Cost
C_E – Reduced Efficiency Cost
C_{WC} – Lost-Water Commodity Cost

APPENDIX B

START / STOP COSTING PROTOCOLS

Maintenance Cost
Equipment Replacement Cost
Water Energy Cost
Opportunity Cost
Efficiency Cost
Water Commodity Cost

Maintenance Cost per Start/Stop, C_M

Objective: To determine the increase in maintenance costs C_M attributable to start/stops.

Method: (A spreadsheet is the easiest way to store data and make calculations.)

1. Retrieve the PM (preventive maintenance) cost in $ for each affected component for each year of the study window. Use MAXIMO Query Reports, Standard Reports, Work Orders, ad hoc querying, as needed.

2. Retrieve the CM (corrective maintenance) cost in $ for each affected component for each year of the study window. Be sure to account for any CM directly attributable to start/stops, such as after-hours callout work.

3. Sum the PM and CM costs for a total maintenance cost C_{MT} in $ for each year of the study.

4. Index the total maintenance cost for each year to present value in the last year of the study window (or current year) using the Consumer Price Index (CPI)[21] from the Bureau of Labor Statistics at http://www.bls.gov/data/ To convert a total maintenance cost C_{MT} in one year to the last year of the window, divide the CPI for the last year by the CPI for the year of interest and multiply by C_{MT}, as found above. For example, for a maintenance cost C_{MT} of $10,000 in 2002 (CPI of 179.9), the comparable cost in 2011 (CPI of 224.9) is:

$$C_{MT}\ (\$2011) = [224.9 / 179.9] \times \$10{,}000 = \$12{,}501$$

5. Find the average annual indexed cost C_{MT1} by dividing C_{MT} found in step 4 by the number of years in the first study window (the years that the unit was operated with fewer starts). Find the average annual indexed cost C_{MT2} for the second time window (the years that the unit was operated with increased starts) in similar fashion.

6. Find the average annual increase in maintenance cost C_{MI} between windows 1 and 2 by subtraction.

$$C_{MI} = C_{MT2} - C_{MT1}$$

7. From operations records, determine the average annual number of starts/stops in each time window. Subtract to find the average annual number of increased start/stops N_{SS} from window 1 to window 2.

[21] Use the general CPI rather than, for example, the energy sector CPI which is influenced by volatile oil prices. An alternative is to use Reclamation construction cost indices.

8. Divide the average annual maintenance cost increase C_{MI} by N_{SS} to find the Maintenance Cost per Start/Stop, $C_{M.}$

$$C_M = C_{MI} / N_{SS}$$

Data Collection and Costing Protocol

Equipment Replacement Cost per Start/Stop, C_R

Objective: To determine the equipment replacement cost C_R attributable to start/stops using estimated deterioration.

Refer to Tables ER-1 and ER-2. A spreadsheet may be substituted for Table ER-1.

Method:

1. Determine the service-life average annual number of starts for the equipment. This is not the Window 1 average annual number of starts used in other cost factor calculations, but rather is the number of starts expected or experienced annually by equipment over its expected life.[22]

2. (Optional) Multiply the service-life average annual number of starts found in step 1 by the EPRI 10-hour-per-start/stop estimate to get the EPRI annual service life in hours supposedly lost to start/stops. (Note that the EPRI calculations are performed for comparison purposes only; the EPRI estimate is of limited value; see Appendix D. The Reclamation loss of life estimate is independently determined.)

3. (Optional) Divide the annual service life lost found in step 2 by the number of hours in one year (8760) multiplied by the plant or unit factor. This is the annual lost life (based on EPRI) caused by start/stops as a percentage of one year. Enter this value as the % replacement cost for start/stop (EPRI) for each component in Table ER-1. The remaining percentage of the lost life (replacement cost) per year is assumed to be caused by continuous running, at the given plant factor. The EPRI % replacement cost estimate found in step 3 is likely to be unreasonably high (or low) for many components.

4. Using expert knowledge and experience, assign a Reclamation percent replacement cost from start/stop in Table ER-1. The EPRI estimate may be useful as a starting place for discussion. Also, use the tools shown in Table ER-2 for each component to arrive at the Reclamation % replacement cost from start/stop.

   Note that the Reclamation percent loss of life figures for each component can be estimated directly, without considering the EPRI percent replacement cost estimate.

5. Multiply the Reclamation percent replacement cost by the annual equipment replacement cost to determine the annual cost in $ lost to start/stop. Enter these values for each component in Table ER-1.

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[22] Service lives are estimated in years, not in number of start/stops. Therefore, until consensus is reached as to what constitutes a "normal" number of annual starts, the service-life annual number of starts must be estimated.

6. Divide the annual cost in $ lost to start/stop found in step 5 by the service-life average annual number of starts found in step 1 and enter in Table ER-1. This is the equipment replacement cost per start/stop of each component.

7. Sum the equipment replacement costs per start/stop for all components to arrive at the Equipment Replacement Cost per Start/Stop, C_R , on Table ER-1.

See the example below for clarification.

Table ER-1. Equipment Replacement Cost per Start/Stop							
EPRI % Replacement Cost From S/S = Service-Life Average Annual Normal # Starts x 10 / (8760 x Plant Factor)							
Component	**Service Life (Yrs)***	**Total Replacement Cost ($)**	**Annual Replacement Cost ($)**	**% Replacement Cost From S/S (EPRI)**	**% Replacement Cost From S/S (Reclamation)**	**Annual Cost From S/S (Reclamation)**	**Replacement Cost per Start/Stop (Reclamation)**
Field Winding	50	350,000	15,000				
Unit Circuit Breaker	35	200,000	5700				
Excitation System	45	700,000	11,100				
Governor	>50	500,000	<15,000				
Turbine Runner	50	1,500,000	15,000				
Thrust and Guide Bearings	>50	275,000	<15,000				
Wearing Rings (Runner)	20	150,000	1500				
Equipment Replacement Cost per Start/Stop, C_R							$

*From Summary of Units of Property and Service Lives, July 1995 to December 2005, Table 2, Replacements book (Western Area Power Administration and Bureau of Reclamation, 2005).

Table ER-2. Loss of Service Life Evaluation Factors

(Use to determine Reclamation % Service Life Lost for Each Component)			
Factor	Query	Determination	Justification / Notes
Diagnostic Testing (on-line and off-line) **	Has diagnostic testing shown component degradation? What portion of the degradation is likely caused by start/stops?		
PM and CM Measurements **	Have PM and CM measurements shown component degradation? What portion of the degradation is likely caused by start/stops?		
hydroAMP Equipment Assessment **	Is the Condition Index ≤ 6 ? Are any Condition Indicators = 0, 1, or 2? What portion of the degradation is likely caused by start/stops?		Index range: 0 – 10 Indicator values: 0,1,2,3
Equipment Failure Codes **	Do failure codes indicate degradation? What portion of the degradation is likely caused by start/stops?		
Machine Condition Monitoring (MCM) **	Does MCM data indicate degradation? What portion of the degradation is likely caused by start/stops?		
Overall Maintenance and Equipment Replacement History	Does maintenance history indicate degradation consistent with start/stops? Is equipment being replaced more frequently? What portion of degradation / replacement is likely caused by start/stops?		
		Reclamation % Service Life Lost (Enter here and in Table ER-1)	%

** See Appendix C of the Hydrogenerator Start/Stop Costs report.

Estimated Deterioration Example – Calculating Equipment Replacement Cost, C_R

Assume a generating unit being operated over several years with 110 service-life average annual number of start/stops. The EPRI % replacement cost attributable to start stops is estimated at 110 x 10 / (8760 x .34) = 37%. The plant factor is assumed to be 34%, a typical hydro plant value. This indicates that the equipment replacement cost per year due to start/stops under these "normal" start/stop conditions is 37% of the total replacement cost for that year. The remaining 63% is assumed attributable to continuous running at plant factor 34%. Initially, these percentages apply to all components.

The 37% deterioration figure is not appropriate for some components and more realistic numbers must be developed. Experts such as engineers and managers use knowledge and experience with plant equipment and the tools found in Table ER-2 to determine the Reclamation percentage replacement cost due to start/stops. In this example, the experts decide that the actual % replacement cost of the circuit breaker is more realistically 50% and they determine that the actual % replacement cost for the governor is about 5%.

Multiplying the annual unit breaker replacement cost of $5,700 by 50% yields $2850 and the annual governor replacement cost of $15,000 by 5% yields $750. Dividing by 110 service-life starts per year yields $25.91 and $6.82 per start/stop, respectively.

Note that costs are expressed in present value because the total replacement cost is in present value. This example is illustrated in the table below.

The same methodology can be used to calculate the replacement cost for each component and then rolled up into a total unit Equipment Replacement Cost per Start/Stop, C_R.

EXAMPLE Table ER-1. Equipment Replacement Cost per Start/Stop

EPRI % Replacement Cost From S/S = Service-Life Average Annual Normal # Starts x 10 / 8760 = 110 x 10 / (8760 x .34) = 37%

Component	**Service Life (Yrs)**	**Total Replacement Cost ($)**	**Annual Replacement Cost ($)**	**% Replacement Cost From S/S (EPRI)**	**% Replacement Cost From S/S (Reclamation)**	**Annual Cost From S/S (Reclamation)**	**Replacement Cost per Start/Stop (Reclamation)**
Field Winding	50	350,000	7,000	37			

Unit Circuit Breaker	35	200,000	5700	37	50	2850.00	25.91
Excitation System	45	700,000	15,600	37			
Governor	>50	500,000	<10,000	37	5	<750.00	<6.82
Turbine Runner	50	1,500,000	30,000	37			
Thrust and Guide Bearings	>50	275,000	<5,500	37			
Wearing Rings (Runner)	20	150,000	7500	37			
						Equipment Replacement Cost per Start/Stop, C_R	$

Data Collection and Costing Protocol

Water Energy Cost per Start/Stop

Objective:

To determine the water energy cost C_{WE} attributable to start/stops. Water energy is energy that could have been generated at full load with water used during a start.

This cost must be considered with Water Commodity costs to prevent “double counting”. Whether or not both costs are included depends on whether water is delivered to end-users via the generator.

Method:

The method requires knowing the volume of water required for a start. Then, knowing the flow rate at full load, the amount and value of electrical energy that could have been generated with this water can be calculated.

Calculations for water volume used during a start required for this calculation are the same as for the Water Commodity Cost process which can be transferred to this calculation.

1. Determine the total volume of water V_T in ft^3 used during a start. See the calculations in the Water Commodity Cost procedure.

2. Acquire the flow rate Q_{FL} in ft^3/sec at full load.

3. Divide the total volume V_T by the flow rate at Q_{FL} and by 3600 to determine the number of hours of generation at full load the starting water could have generated.

4. Multiply the result from step 3 by the full load rating in MW and by the power rate in $/MW to calculate the Water Energy Cost C_{WE} .

$$C_{WE}(\$) = (V_T \text{ x } MW_{FL} \text{ x } \$/MWH) \;/\; (Q_{FL} \text{ x } 3600)$$

Data Collection and Costing Protocol

Availability Cost per Start/Stop

Objective:

To determine the availability cost C_A attributable to start/stops. Availability to generate may be reduced by increased outages caused in part by increased start/stops.

Method:

(A spreadsheet may be the easiest way to store data and make calculations.)

1. Retrieve the availability factor for each year of the study window, using operations records.

2. Calculate the average annual availability factor for the first time window ("normal" start/stops) and for the second time window (increased start/stops).

3. Calculate the average annual outage factor (forced plus planned) for each window by subtracting the average annual availability factors found in step 2 from 100.

4. Subtract the average annual outage factor for window1from that for window 2, found in step 3, to arrive at the difference in average annual outage factor. (Assumes outage factor is higher in the increased start/stop window).

5. Multiply the difference in average annual outage factor found in step 4 by 8760 hours per year to arrive at the difference in lost availability time in hours per year due to outages, T_A.

6. Determine the plant (or unit) factor = (Gross Generation in MW x 100) / (Capacity in MW x 8760 hrs per year).

7. Multiply the difference in lost availability time T_A found in step 5 by the plant or unit factor and by the rated capacity, MW_{Rated} to determine the average annual MWH generation lost to unavailability.

8. Multiply the average annual MWH of lost generation found in step 7 by the current generation power rate to find the average annual cost of unit unavailability in $.

   The power rate used should be determined locally. Generally, the current composite rate is used, but the peaking rate may be used, instead. A more accurate method of calculating the cost may be achieved by calculating the lost revenue per year using that year's power rate and then indexing for inflation.

Note that this step assumes that ALL of the reduced availability is due to change in unit operation from “normal” to high start/stop operation . Operations expertise is needed to decide whether this is a reasonable assumption, or whether this figure should be reduced due to other operational changes.

9. Using operations records, determine the average annual increase in the number of start/stops, $N_{SS,}$ before and after increased start/stop operation.

10. Divide the average annual cost of unavailability found in step 8 by the average annual increased number of start/stops N_{SS} found in step 9 to determine the availability cost per start/stop, C_A.

    Availability Cost per Start/Stop, C_A (\$) =
    $[T_A \times \text{Plant Factor} \times MW_{Rated} \times \$ / MWH] / N_{SS}$

11. Adjust the availability start/stop cost to reflect actual start/stop impact. The availability start/stop cost found in step 10 may be unrealistically high. If other factors have impacted unit availability, then only a fraction of outage numbers and lengths is due to start/stops.

    Review the maintenance and equipment replacement/rehabilitation records to determine what percentage of outages were likely associated with start/stops. Multiply this percentage by the availability start/stop cost found in step 10, to arrive at a final, adjusted C_A.

Data Collection and Costing Protocol

Opportunity Cost per Start/Stop

Objective:

To determine the opportunity cost C_O attributable to start/stops. Opportunity to generate may be lost due to the unit being held out of normal operation to provide increased non-spinning and replacement reserves.

Initially, the method compares net generation (MWH) between periods of low and high number of starts. However, increased starts may also have the effect of shifting generation from peak to non-peak periods. Thus, the opportunity cost may be better reflected by comparing net revenue ($). Although revenue values may not always be known at the Reclamation plant level, this method should be considered and is represented by references in brackets [ ].

Method:

(A spreadsheet may be the easiest way to store data and make calculations.)

1. Retrieve net generation in MWH [net revenue] for each year of the study window. Use operations / generation records.

2. Calculate the average net generation in MWH [net revenue] in the first study window (unit operating without increased starts) and in the second window (after increased starts).

3. Subtract the average net generation [net revenue] in window 2 from that in window 1, found in step 2, to find the difference (i.e., reduction) in average net generation [net revenue] between the two windows, MWH_D.

4. Multiply MWH_D found in step 3 by the generation power rate to arrive at a total opportunity cost between the two time windows. [Use the differential net revenue calculated in step 3].

   The power rate used should be determined locally. Generally, the current composite rate is used, but the peaking rate may be used, instead. A more accurate method of calculating the cost may be achieved by calculating the lost revenue per year using that year's power rate and then indexing for inflation.

   Note that this step assumes that ALL of the opportunity cost is due to the change in unit operation from "normal" to high start/stop operation . Operations expertise is needed to decide whether this is a reasonable assumption, or whether this figure should be reduced due to other operational changes.

5. Using operations records, determine the difference in average number of start/stops, N_{SS}, between the unit before and after increased start/stop operation.

6. Divide the total opportunity cost found in step 4 by the increased number of start/stops N_{SS} found in step 5 to arrive at an opportunity cost per start/stop, C_O.

$$\text{Opportunity Cost per Start/Stop, } C_O \text{ (\$)} = [MWH_D \times \$ / MWH] / N_{SS}$$

Efficiency Cost per Start/Stop

Objective:

To determine the efficiency cost C_E attributable to start/stops. Efficiency reduction results from increased turbine runner cavitation caused by increased start/stops.

Discussion:

This protocol assumes that efficiency loss is largely attributable to turbine cavitation and that start/stop loss of efficiency is a fraction of the overall efficiency loss. The calculation includes two components: 1) a water commodity cost, created when more water is required to generate energy at lower efficiency, and 2) an opportunity energy cost created when the water lost to increased inefficiency is not available for generation.

Whether the water commodity portion of this cost should be included in start/stop cost calculations depends on how water is valued and used at a project. See the Water Commodity Cost protocol for more discussion.

Assume a constant head for all calculations.

Method – Efficiency Commodity Cost:

1. Determine the percentage loss of turbine efficiency from field measurements. Generally, this is done by comparing the efficiency measurements when the turbine was commissioned to those taken many years later, just before replacement (if available). Otherwise, estimate the percentage loss of turbine efficiency.

2. Estimate the percentage of the efficiency loss found above that is attributable to start/stops. This estimate is comparable to that used for turbine degradation in the Equipment Replacement Cost protocol.

3. Calculate the start/stop efficiency loss percentage by multiplying the results of steps 1 & 2:

Start/Stop % Efficiency Loss = Total Efficiency % Loss x Estimated Loss % from Start/Stop

For example: If the total % efficiency loss due to cavitation is 5% and if it is estimated that 20% of this loss is due to start/stops, then:

Start/Stop % Efficiency Loss = 5% x 20% = 1%

4. Acquire the flow rate at full load Q_{FL} in cfs. Calculate the total flow rate Q_T in cfs per MWH by multiplying the full load flow rate by 3600 (seconds/hr) and dividing by the full load rating.

$$Q_T\ (ft^3/MWH) = Q_{FL} \times 3600 / MW_{Rated}$$

5. Calculate the flow rate per MWH due to start/stops Q_{SS} by multiplying the result of step 4 by the start/stop % efficiency loss calculated in step 3.

$$Q_{SS}\ (ft^3/MWH) = Q_T \times \text{Start/Stop \% Efficiency Loss}$$

6. Acquire the average annual net generation in MWH. Calculate the annual volume of lost water in one year from start/stops by multiplying the total energy by the result of step 5.

$$V_{SS}\ (ft^3) = MWH_{Annual} \times Q_{SS}$$

7. Calculate the volume of lost water in acre-feet (AF) by dividing the result found in step 6 by 43,560. Calculate the start/stop efficiency commodity cost for one year by multiplying again by the commodity price of water in \$ / AF. Calculate the efficiency commodity cost per start stop, C_{EC} by dividing by the average annual number of starts. These steps combined:

$$C_{EC} = ((V_{SS} / 43{,}560) \times \$/AF) \ / \ \text{Annual \#Starts}$$

This result should be adjusted. It calculates the loss of water in a "worst case" year, when efficiency is lowest. Over the life of the turbine, efficiency loss starts out at zero and gradually increases to the maximum as measured at end of life. The loss-of-efficiency curve is likely non-linear, but the exact shape is unknown[23] due to lack of data (unless efficiency measurements have been taken on a periodic basis, not currently a Reclamation practice). This means that the volume of water per start/stop lost due to start/stop cavitation is not fixed over time. Without knowing the exact shape of the curve, it is initially reasonable to <u>assume an exponential relationship between loss of efficiency and time and thus the cost per start/stop should be divided by 2.4</u> for a more reasonable figure. This method can be revised as more data regarding the shape of the loss-of-efficiency curve over time becomes available and the non-linearity accounted for.

Method – Efficiency Lost-Opportunity Cost:

1. Acquire the average annual net generation. Calculate the annual generation in MWH lost to start/stop efficiency loss by multiplying the average annual net generation by the start/stop % efficiency loss found in step 3 of the lost commodity cost methodology, above.

Annual generation loss from start/stop efficiency loss (MWH) =
    Average annual net generation (MWH) x Start/Stop % Efficiency Loss

[23] In fact, the curve may not be "smooth", as turbine cavitation is periodically repaired by welding in new material.

2. Calculate the efficiency lost-opportunity cost per start/stop, C_{EO} by multiplying the result in step 1 by the power rate and dividing by the average annual number of starts.

$$C_{EO} (\$) = \text{Annual generation loss (MWH)} \times \$/\text{MWH} / \text{Annual \# Starts}$$

Similar to the discussion above regarding commodity cost, C_{EO} should be adjusted. It calculates the loss of generation in a “worst case” year, when efficiency is lowest. Over the life of the turbine, efficiency loss increases as cavitation increases. Initially, it is reasonable to assume an exponential relationship between loss of efficiency and time <u>and the estimate above should be divided by 2.4</u> for a more reasonable figure. This method can be revised as more data regarding the shape of the loss-of-efficiency curve becomes available and the non-linearity accounted for.

Method: Total Efficiency Cost, C_E

Calculate the Efficiency Cost per Start/Stop, C_E by adding the efficiency commodity cost C_{EC} to the efficiency lost-opportunity cost C_{EO}:

$$C_E (\$) = C_{EC} (\$) + C_{EO} (\$)$$

Water Commodity Cost per Start/Stop

Objective:

To determine the water commodity cost C_{WC} attributable to start/stops. Water commodity costs result from inability to sell water used for start/stops.

Discussion:

This cost must be considered with Water Energy costs to prevent “double counting”. Whether or not both costs are included depends on whether water is delivered to end-users via the generator.

Whether this cost should be included in start/stop cost calculations depends on how water is valued and used at a project. Water always has a monetary value and if water used during a start is truly lost for other purposes (e.g., lost from the reservoir where it could have been pumped for irrigation or not useable for generation), it is valid to include the lost commodity cost as part of the start/stop cost.

Where water released during a start is simply delivered to a water customer who pays for it, there is no lost-water commodity cost and it should not become part of the start/stop cost.

This analysis assumes the “worst case scenario” where the water used during a start/stop is lost as a salable commodity and as “fuel” for generation, i.e., Water Energy.

Water lost during a start consists of four components:

- From start to speed-no-load (SNL)
- From SNL to synchronism
- From operating in turbine less-efficient zones during ramp up from no load
- From operating in turbine less-efficient zones during ramp down to no load

Method:

Measuring the volume of water used in starting and stopping is challenging. In fact, Reclamation has never made this measurement. Thus, it is necessary to estimate the volume of lost water using elapsed time and flow rates.

Many generating units are equipped with flowmeters. However, these meters work best at steady-state conditions; they do not respond quickly enough to capture changing flow rates during startup and shutdown. Thus, the changing flow rate during startup is unknown.

Start to SNL

Flow starts at zero, then the gates are opened (e.g., 20% - 30%) to establish water flow substantial enough to overcome inertia of the unit. Then, gate position (and flow) is reduced as the unit nears rated speed. How linear the relationship of flow with time is depends somewhat on how well the governor controls gate opening. It is likely somewhat non-linear, but the shape of the curve is unknown and, therefore, the volume of water difficult to calculate. Thus, it is necessary to estimate by assuming a constant flow during the startup.

1. Determine the volume of water used to bring the unit from stop to speed-no-load (SNL), V_{SN}, as follows:

Measure the time in seconds T_{SN} that it takes for the unit to go from start (gates beginning to open or breakaway) to rated speed (SNL). Using a flowmeter, measure the flow rate Q_{NL} of water in cubic feet per second (cfs) at SNL. If a flowmeter is not available, assume this flow to be approximately 6% of flow at rated output, which is normal for most hydro units.

Assume a constant flow: multiply the time measured in seconds by the flow rate in cfs to calculate the volume of water V_{SN} in cubic feet from stop to SNL.

$V_{SN} = T_{SN} \times Q_{NL}$ (or, using the 6% estimate, $V_{SN} = T_{SN} \times .06Q_{FL}$,where Q_{FL} is the flow at rated/full load)

SNL to Synchronism

2. Determine the volume of water used to keep the unit at SNL until synchronism, V_{NS}, as follows:

Measure the time in seconds T_{NS} that it takes for the unit to go from SNL to synchronism.

Multiply the time measured in seconds by the flow rate at SNL in cfs to find the volume of water V_{NS} in cubic feet from SNL to synchronism.

$V_{NS} = T_{NS} \times Q_{NL}$
(In lieu of Q_{NL}, use the 6% of Q_{FL} flow estimate, if flowmeter not available).

The volume of water used between SNL and stop is zero because when the load is decreased to zero, the gates are closed and water no longer passes.

Synchronism to Load

3. Determine the volume of water lost to inefficient operation during ramping the unit from synchronized at no load to 50% of full load, V_{RU}. 50% is chosen as the beginning of the most

efficient portion of the turbine efficiency curve, which is the preferred place to operate. This is accomplished as follows, using the turbine efficiency curve (see Figure WC-1):

A. Determine the average efficiency, E_A, between 50% load (where the curve begins to level out) and full load. This will be an approximate value.

B. Determine the efficiency and flow at 10% increments between zero load and 50% load (10%, 20%, 30%, 40%, 50%).

C. Calculate the volume of water lost per increment, V_I, by multiplying the flow at that increment, Q_I, by the difference between the average efficiency, E_A , and the efficiency of that increment, E_I, and by 60 seconds. Sixty seconds is used because the Reclamation maximum ramp rate is 10% per minute.

$$V_I = Q_I \times (E_A - E_I) \times 60$$

D. Calculate the volume of water lost during ramping up, V_{RU} by summing V_I for all five increments:

$$V_{RU} = V_{RI10} + V_{RI20} + V_{RI30} + V_{RI40} + VR_{I50}$$

Load to No Load

4. The rate of unloading a unit is the same as for ramping up, 10% per minute. Therefore, the volume of water lost during ramping down, V_{RD}, is the same volume as for ramping up.

Total Lost Water

5. Determine the total volume of lost water in cubic feet during the start by adding the elements.

$$V_T = V_{SN} + V_{NS} + V_{RU} + V_{RD}$$

6. Determine the cost of water in cubic feet.

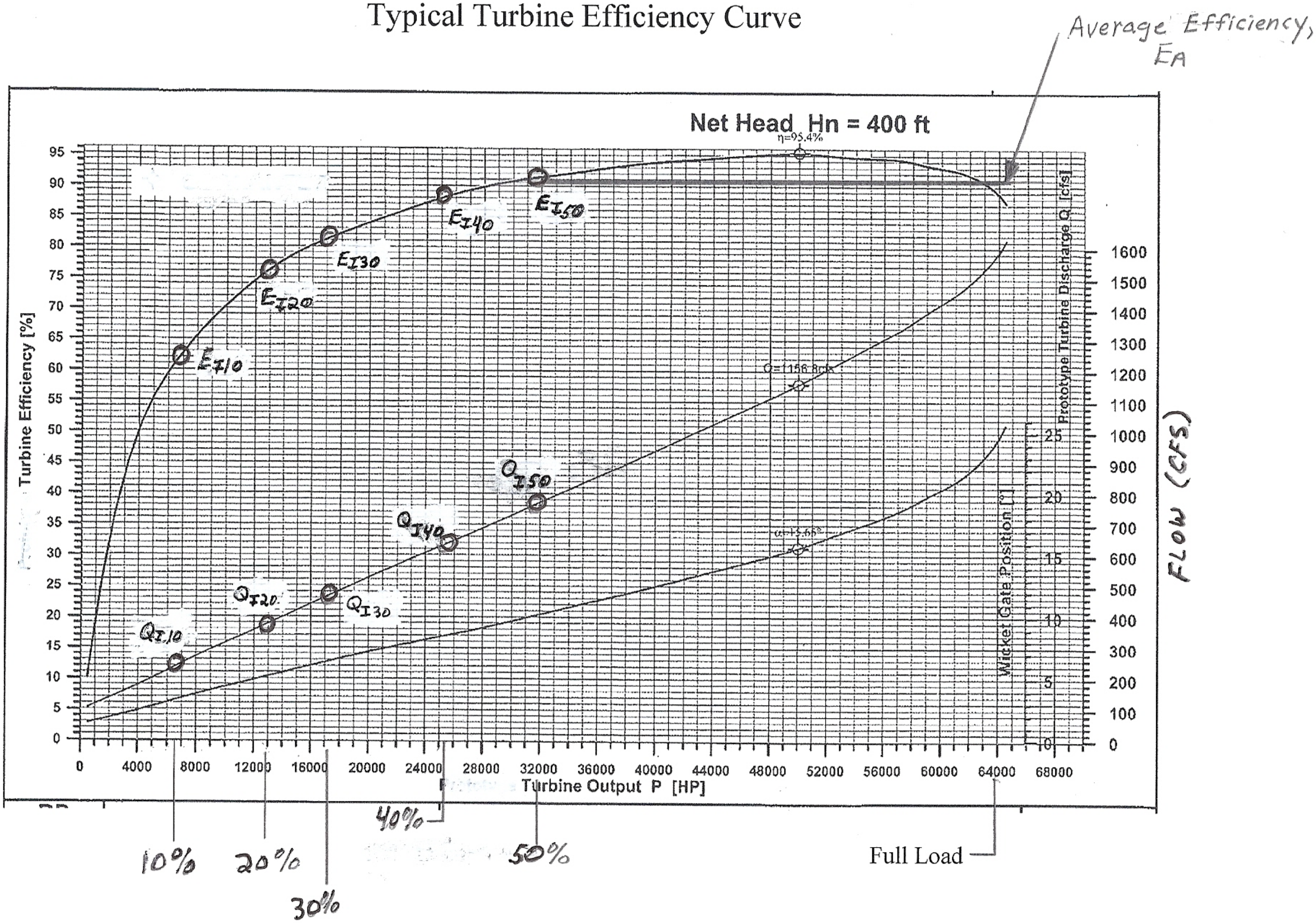
The commodity price of water is usually in \$ per acre-foot. Divide this price by 43,560 to find the cost of water in cubic feet.

$$\$ / ft^3 = \$ \text{ per acre-foot} / 43{,}560$$

7. Determine the Water Commodity Cost, C_{WC} by multiplying V_T by \$ / ft^3

$$\text{Lost Water Commodity Cost per Start/Stop, } C_{WC} (\$) = V_T \times \$ / ft^3$$

Figure WC-1
Typical Turbine Efficiency Curve



APPENDIX C

Equipment Deterioration Assessment Tools

There are several existing tools available in Reclamation to help quantify the causes, effects, and extent of equipment degradation. These tools can be used to help determine the portion of deterioration caused by start/stops (vs. continuous operation). Although engineering judgment is required, these tools can make the process of costing start/stop loss of equipment service life and increased maintenance less subjective.

Diagnostic Testing and Maintenance Measurements

Reclamation's FIST Volumes[24] define required maintenance for electrical and mechanical equipment. This includes diagnostic testing and measurements that should be conducted and recorded in the maintenance management system, MAXIMO. Examination of these data will help determine equipment condition and possibly whether degradation is attributable to start/stops.

hydroAMP

Data collected through diagnostic testing and maintenance should be entered into MAXIMO where they are used by the hydroAMP module to assign a Condition Indicator and then calculate an equipment Condition Index. This can be useful in evaluating degradation in equipment.

The hydroAMP system was developed by Reclamation, the Corps of Engineers, Bonneville Power Administration, and Hydro Quebec to evaluate and document the condition of hydropower equipment and facilities in order to support business decision-making. The hydroAMP condition index feeds data to the Facility Reliability Rating (FRR) system which is mandated by the Department of the Interior.

As part of hydroAMP, Risk Assessment Guides have been prepared for most major electrical and mechanical equipment. The following guides are complete or in development:

- Generator
- Generator Core
- Step-Up Transformer
- Unit Circuit Breaker
- Exciter
- Surge Arresters
- Battery
- DC Charging System
- Station-Service AC System
- Governor

[24] Facilities Instructions, Standards, and Techniques

- Turbine
- Air Compressor System
- Cranes
- Emergency Gates and Closure Valves
- Spillways and Regulating Systems

HydroAMP is a two-tiered system:

- **Tier 1 –** relies on test results and/or inspections that are normally obtained during routine maintenance activities. These **Condition Indicators** are weighed together to compute an equipment **Condition Index**. The index ranges from 10 to 0 and equates to a good, fair, or poor rating.

- **Tier 2 –** is used to further investigate abnormal Tier 1 results and relies on more in-depth, non-routine tests and inspections requiring specialized knowledge, diagnostic equipment or outages. These results refine or adjust the Tier 1 **Condition Index**.

The hydroAMP method includes weighting factors for method importance and data quality.

The condition index and condition indicators provide the experts with information to help determine equipment condition and possibly whether degradation is attributable to start/stops.

Failure Codes

The MAXIMO maintenance management system used by Reclamation includes failure code analysis tools. These are often used for corrective maintenance when a problem or failure has occurred.

There are 97 failure classes defined in MAXIMO which identifies the component associated with the failure. Once the failure class has been identified, maintenance personnel identify the problem, cause, and remedy from the predefined list and enter them into the corrective maintenance work order.

An example: Failure Class: Breaker
Problem: Out of adjustment or alignment
Cause: Improper adjustment / improperly installed / maintenance faulty or deferred / operator error
Remedy: Adjust, calibrate, set / repair / replace / training

Properly used, failure codes provide the experts with information to help determine equipment condition and possibly whether degradation is attributable to start/stops.

Machine Condition Monitoring

On-line MCM can provide real-time data that can be used to better understand equipment condition and causes of degradation. This can help determine whether degradation is attributable to start/stops. Unfortunately, MCM use in Reclamation is limited for several reasons:

- Cost of equipment, installation, and maintenance
- Data evaluation and interpretation is challenging and time consuming
- MCM not currently applicable to all equipment
- Poor experience with MCM systems, in the past

Where MCM is used, the data can help in the degradation assessment.

APPENDIX D

Start / Stop Loss-of-Service-Life Estimates

Quantifying the degree of hydro plant equipment degradation – loss of service life – due to increased start/stops is important to calculating start/stop costs. Several studies in the literature use a "rule of thumb", estimating that each start reduces equipment life by 10 hours.

The source cited for this rule of thumb is EPRI "Hydropower Technology Roundup Report: Accommodating Wear and Tear Effects on Hydroelectric Facilities Operating to Provide Ancillary Services" (2001) [10]. This report, in turn, cites an earlier EPRI report, "EPRI Hydropower Reliability Study", (1984) [9], as the source for this 10-hour estimate.

The industry studies then use this estimate in calculating the cost of starts, to distinguish the start/stop cost from the cost of degradation due to normal running wear and tear.

While convenient, the 10-hour-per-start estimate should be used carefully, if at all. There are several considerations:

- The rule of thumb overestimates the effect of start/stop degradation. For example: A generating unit started twice a day to match peak loads would log 7300 starts in ten years or the equivalent of 73,000 hours of routine operation in starts alone. If the unit operated at load an average of 6 hours per day over the ten years, the total aging effect would be 94,900 hours (life lost to start/stop + running time). By comparison, ten years of 24-hour days equals 87,600 hours. Clearly, the 10-hour per start loss-of-life figure overstates the aging effect.

  In fact, the EPRI Reliability Study (pp. C. 3-20 through C. 3-23) cautions that estimates will be incorrect" if running time is used as the only criterion." However, it does not say how to mitigate the error.

- Although used in the studies as a general rule of thumb applicable to all components, the estimate apparently is only for generator winding life expectancy. Discussion in the EPRI Reliability Study only appears in the section titled, "Winding Insulation Life Expectancy" (starting page C. 3-19).

  It is difficult to be sure that the 10-hour estimate applies only to windings as it is based on research published in the following article (paper?) which this author has not been able to locate:

  > W. Zwicknagel. OeDK Klagenfurt. "Zur Revision von Generatoren," Elektrizitatswirtschaft, Jg. 79 (1980) Heft 18.[25]

[25] Reference 1., pg C. 3-72, in the EPRI Reliability Study which states it as research by the Association of German Utilities.

Even if use of the 10-hour estimate is confined to stator winding insulation, it is based on an article dated 1980 which undoubtedly uses data decades old at that time. Insulation design and materials have improved greatly in the past 32 years and the 10-hour estimate may no longer be valid.[26]

Part of the confusion as to whether the 10-hour estimate is applicable to components other than the winding may come from the statement in the Reliability Study, Section 2, Recommendations (pg. 2-4), “It has been determined that a start/stop cycle ages the machine by an equivalent of 10 hours”. The term “machine” could be construed as the entire generating unit.

Also, the 10-hour estimate is the only known published “hard number” for estimating start/stop loss-of-life and its use as a general rule-of-thumb may simply have been too great to resist when conducting the costing studies.

- Any fixed loss-of-service-life number does not take into account that different equipment will be affected to different degrees by start/stops. Even if 10 hours per start is reasonable for one component, it will not be reasonable for others. For example, durable mechanical components such as turbine runners and water passages will be less degraded than circuit breakers and governors.

Therefore, if the 10-hour-loss-of-life-per-start estimate is used, it should be used cautiously. It may be used as a starting place, giving a “worst case” estimate for a component and then modified by subject matter experts, using experience and other data to arrive at a reasonable loss of life unique to each component and to each plant.

[26] And there is disagreement in the industry whether winding life is significantly affected by start/stops.

APPENDIX E

Generator Start/Stop Cost Model Input Data Requirements

This section summarizes the data required to make full use of the generator start/stop cost model. Once collected, the data can be used with the Data Collection and Costing Protocols to calculate the cost factors and the total start/stop cost, C_{SS}. See those protocols for more detail on how the data are used in the model.

If the input data are used in a Reclamation start/stop spreadsheet,[27] the spreadsheet will perform all necessary start/stop cost calculations and will include the following: a list of all potential components for replacement cost considerations (user selects which ones to use) and service lives for each component from the Replacements book. User must enter equipment component replacement cost data, since data will vary by unit size and with year. In the spreadsheet model, data are input only once and the spreadsheet calculates the various cost factors, as indicated with an X in the following table.

Generator Start/Stop Cost Model Input Data Requirements* April 6, 2012 (Refer to the Data Collection and Costing Protocols for More Information)			
Symbol	Name	Definition	
	Powerplant Name	Name of powerplant where start/stop cost study is being performed.	
	Unit Number	Number of the generator being studied for start/stop costs.	
	Total Study Length	Total length of the study in years. This is the sum of Study Windows 1 and 2.	

[27] Not currently available.

					C_G				
			C_M	C_R	C_{WE}	C_A	C_O	C_E	C_{WC}
MW_{Rated}	Rated Capacity	Full-load capacity in MW of the unit being studied.			X	X			
	Study Window 1 (Normal) Length	Length of Study Window 1 (when starts were considered normal) in years.	X	X		X	X	X	
	Study Window 2 (High Starts) Length	Length of Study Window 2 (when starts were higher than normal) in years.	X	X		X	X	X	
	CPI	CPI (Consumer Price Index) for each year of the study. CPI found at http://www.bls.gov/data/	X						
	Annual Number of Starts	Number of unit starts for each year of the study.	X	X		X	X	X	
	Annual PM Cost	The annual PM cost in $ of each component* including labor, parts, materials, and services. Includes operations and overhead costs.	X						
	Annual CM Cost	The annual CM cost in $ of each component* including labor, parts, materials, and services. Includes operations and overhead costs.	X						
	Replacement Cost	Cost in $ of replacing or rehabilitating the components being considered for start/stop replacement costs.		X					
	Reclamation Start/Stop % Replacement Cost	Estimated % replacement cost (loss of life) of each component attributable to start/stops.		X				X Turb	
T_{SN}	Time from Start to SNL	Time in seconds for the generator to go from dead stop to speed-no-load during a start.			X				X

T_{NS}	Time from SNL to Sync	Time in seconds for the generator to reach synchronism after reaching speed-no-load during a start.			X				X
	Composite Power Rate	Power rate in $/MWH.			X	X	X	X	
	Availability Factor	Unit availability factor in % for each year of the study.				X			
	% Outage Duration from Start/Stop	Estimated % of total outage time in a study window attributable to start/stop caused problems.				X			
	Annual Net Generation	Net generation in MWH for the unit for each year of the study.					X	X	
	% Loss of Turbine Efficiency	Estimated or measured % loss of efficiency over the length of the study.						X	
	% Loss T. Efficiency from Start/Stop	Estimated % loss of turbine efficiency attributable to start/stop degradation. For simplicity, this can be the same as the Reclamation Start/Stop % Replacement Cost for the turbine runner used in the Replacement Cost calculations.						X	
Q_{FL}	Flow Rate @ Full Load	Flow rate in cfs of water used to operate the unit at rated load. Assume rated head.			X			X	X**
	Water Commodity Price	Value of water in $ per acre-ft.						X	X
Q_{NL}	Flow Rate @ Speed-No-Load	Flow rate in cfs of water used to operate the unit at speed-no-load. Assume rated head.							X
Q_{I10}, Q_{I20}, Q_{I30}, Q_{I40}, Q_{I50}	Flow Rate @ 10, 20, 30, 40, 50% Rated Load	Flow rate in cfs of water used to operate the unit at 10% increments between zero and 50% load. Assume rated head.			X				X

E_A	Average Turbine Efficiency	Approximate average turbine efficiency between 50% load and full load.			X				X
E_{I10}, E_{I20}, E_{I30}, E_{I40}, E_{I50}	Turbine Efficiency @ 10, 20, 30, 40, 50% Rated Load	Turbine efficiency unit at 10% increments between zero and 50% load.			X				X
Plant or Unit Factor	Average Plant or Unit Factor	Plant factor % = (Gross Generation in MW x 100) / (Capacity in MW x 8760 hrs per year)		X		X			

*Includes all components / systems of the generator, not just the ones considered for replacement costs.

**When flowmeters are not available.

APPENDIX F

CASE STUDY – Start / Stop Costs

Flaming Gorge Powerplant

Introduction

Flaming Gorge Powerplant was compared to the case study selection criteria, outlined in the body of the report.

Flaming Gorge Comparison to Selection Criteria

Criteria	Comments
Increased Start/stops	Significant increase in start/stops.
Peer Units	The three units at Flaming Gorge are of essentially identical design and construction.
Maintenance Data	MAXIMO is used to plan, schedule, and track maintenance.
Financial Data	Available from FFS with some data from MAXIMO
Turbine Efficiency Data	Available only for original turbines and replacement runners when new
Water Commodity Value	Water has a commodity value
Management Receptivity	Receptive to participation.

Flaming Gorge was considered a good candidate for testing the start/stop cost model. Of primary importance was the starting history.

Flaming Gorge Start History (by FY)

	Unit 1	Unit 2	Unit 3	Plant
Total Starts 2000-2005	208	160	170	538

Total Starts 2006-2011	675	496	507	1678
Increase in Total Starts	467	336	337	1140
% Increase	225	210	198	212

These data showed a very large increase in individual and plant starts between the two 6-year time windows. They also showed a significant differential in starts between Unit 1 and the other two units in both windows (approx. 22-30% during 2000-2005 and 39% during 2006-2011). This implied that it should be possible to compare costs and potentially arrive at an identifiable start/stop cost.

General Data

Features and Characteristics

- Year of initial operation: 1963
- Installed capacity: 151,950 kW
- Rated Head: 400 ft
- Net Plant Generation: 640,924,695 kWh (2011)
- Three 50,650-kilowatt generators, uprated 1991-1992
- Turbines: 50,000-horsepower Francis-type turbines, replaced 2005 to 2008
- Unit transformers replaced in 2002 and 2003
- Excitation: Static. Replaced 1990-1992
- Governors: Mechanical, original equipment
- Plant Factor: 48.34 percent (2011)
- Average Plant Factor (2000-2006): 31.4%
- Production Mode: Intermittent
- Remotely Operated

Ancillary Services Provided

- Spinning Reserve
- Non-Spinning Reserve
- Replacement Reserve
- Regulation/Load Following
- Black Start
- Voltage Support

Staffing

The Operations and Maintenance Group has 15 positions, including electricians and mechanics. Five other positions support the O&M staff and include an electrical engineer (position currently vacant), a mechanical engineering technician, and a facilities maintenance technician primarily responsible managing work via the CMMS system, MAXIMO. Other staff at the Flaming Gorge Field Division include administrative and warehouse personnel. The field division manager is located at Flaming Gorge Dam.

Powerplant O&M staffing levels have remained relatively constant over the last decade.

Most maintenance is done with in-house staff. Specialists from the Reclamation Technical Service Center (TSC) are used when needed. Major replacement and rehabilitation projects are done via contract with the private sector.

Powerplant Operation

The powerplant is continuously available for generation. However, it is staffed only Monday-Friday during the day shift. At nights and on weekends staff are on site only if called out for an emergency or malfunction. The plant is normally operated remotely via the SCADA system, including starting and stopping. Energy and ancillary services are marketed through the Western Area Power Administration (WAPA).

There is no operator position per se at Flaming Gorge. Several craftspeople have dual classifications (and proper training) to allow them to operate the generators in local-manual mode, when necessary. When operating the units for maintenance purposes (e.g., unit annual PM), labor associated with operating the units is charged to the maintenance work order. Otherwise, operations is charged to a standing (continuously open) work order associated with the highest level of the equipment hierarchy for that generating unit.

Data Collection and Costing of Factors

Because Unit 1 showed the most dramatic increase in number of starts, data analysis and costing focused on Unit 1, comparing costs between the two windows 2000-2005 and 2006-2011. An exception to this is when the analysis required using net generation, which is not tracked by unit. All calculations were done using fiscal years (October-September).

Because of time constraints, analysis was not done on Units 2 and 3, or between units. Much of the data were collected for these other units and could be analyzed later.

Data was collected and start/stop costs were calculated using the general methodology described in the body of this report. The generic data collection and costing protocols found in Appendix B were used to guide the process. The Flaming Gorge data collection and costing details for each cost factor appear at the end of this section.

Start / Stop Cost Summary

Flaming Gorge Unit 1 Start/Stop Cost	
Factor	Start/Stop Cost ($)
Maintenance Cost, C_M	8.00
Equipment Replacement Cost, C_R	145.00*
Reduced Generation Cost, C_G • Water Energy Cost, C_{WE} ($10) • Availability Cost, C_A ($36) • Opportunity Cost, C_O ($0) • Efficiency Cost, C_E ($3)	49.00
Water Commodity Cost, C_{WC}	72.00
Total Cost per Start/Stop, C_{SS}	$274*

*Does not include the cost of stator winding start/stop deterioration. See the Sensitivity Analysis section for costs that include the stator winding.

Data Collection and Costing

Flaming Gorge Powerplant

Maintenance Cost per Start/Stop

Objective

To determine the maintenance start/stop cost, C_M , for Flaming Gorge Powerplant.

Method

The Unit 1 average total maintenance cost was compared between 2000-2005 (when starts were lower) and 2006-2011 (when starts were 225% higher).

Costs were retrieved on a fiscal year basis, to better compare to other costing data.

Because Flaming Gorge operations costs are charged to work orders assigned to MAXIMO locations, the maintenance data retrieved includes operations costs, as well.

Locations in the Flaming Gorge MAXIMO hierarchy capture costs of work orders issued to that location and to all assets (equipment) assigned to that location. Even though locations have parent-child relationships, costs do not roll up from child to parent automatically. Therefore, costs were retrieved by location and analyzed in various ways in a spreadsheet (Table FGM-2).

Table FGM-1 explains the locations queried for maintenance data from MAXIMO.

Table FGM-1

Flaming Gorge Unit 1
Maintenance Work Order Locations Queried in MAXIMO

Location	Name	Explanation
FG-PP-U1	Unit 1	Parent location to Unit 1 child locations
FG-PP-U1-CONT	Control System	
FG-PP-U1-ELEC	Unit 1 Electrical	Misc electrical
FG-PP-U1-ELEC-XMFR	Transformer KR1A	
FG-PP-U1-GEN	Unit 1 Generator	Parent location to generator

		child locations
FG-PP-U1-BRJA	Brakes/Jacking System	Pump, shoes, cylinders
FG-PP-U1-CW	Cooling Water System	Strainers, pumps, coolers, piping
FG-PP-U1-GBO	Generator Bearing Oil System	
FG-PP-U1-GEN-COMP	Generator Components	Upper & lower guide bearings, CO2 system, rotor, stator, thrust bearing, slip rings, brushes
FG-PP-U1-GEN-CRE	Creep Detector System	
FG-PP-U1-HPO	High Pressure Oil System	Lift pump
FG-PP-U1-GOV	Governor	Servomotors, pumps, filters, ballhead, tank, actuator, distributing valve, cabinet, PMG
FG-PP-U1-EXC	Excitation System	Voltage regulator, exciter, field breaker, transformer, bridge, controls
FG-PP-U1-EXC-VENT	Exciter Ventilation System	Fans, filters
FG-PP-U1-INST	Instrumentation	Misc instruments
FG-PP-U1-PROT	Protection System	Relays, small breakers, temperature devices, etc
FG-PP-U1-TURB	Turbine	Parent location to turbine child locations
FG-PP-U1-AG	Automatic Greasing System	Controls, pressure unit, piping
FG-PP-U1-AIRAD	Air Admission System	Solenoids, valves, float switches
FG-PP-U1-BCW	Bearing Cooling Water System	Pumps, motors, strainers, regulators, piping, coolers

FG-PP-U1-TBO	Turbine Bearing Oil System	Pumps, motors, piping
FG-PP-U1-TURBCOMP	Turbine Components	Packing Box, Seal Rings, Wicket Gates, Runner, Turbine Guide Bearing
FG-PP-U1-WTRWAY	Waterway	Scrollcase, Draft Tube

In many cases, cost data were zero, thus neither costs nor locations appear in Table FGM-2.

At Flaming Gorge, most PM on generating unit components is accomplished during the approximate 4-week “unit annual” planned outage. The work orders / job plans covering this annual PM are segregated by craft and include work on many components. For work management purposes, the work orders are assigned to a higher-level location, rather than to the location more closely associated with the component. For example, the “Generator Inspection – Major” job plan is issued under a work order assigned to location FG-PP-U1-GEN. This includes work on the stator, PMG, unit auxiliaries, temperature switches, unit circuit breaker, brushes, slip rings, etc. Theoretically, work on these components would be charged to locations much closer to the component than the higher location FG-PP-U1-GEN. But logistically, it makes more sense to group them, as described. This makes maintenance cost tracking of individual components more challenging.

The unit circuit breaker is not listed in Table FGM-1. That is because the three unit breakers are identified with a common asset numbers in MAXIMO, asset 13497. Therefore, the cost of individual breaker maintenance work charged to this asset number was estimated by prorating the combined costs for asset 13497. As discussed above, most breaker maintenance is accomplished during the unit annual PM and therefore, most of the cost of unit breaker PM for a given unit is captured with other costs for that unit.

The components and locations queried for maintenance costs and their associated cost data are shown in Table FGM-2.

Maintenance Data Collection and Costing Protocol Steps

For Flaming Gorge, the generic protocol[28] for collecting maintenance data and calculating increased maintenance costs was followed.

1. – 3. Retrieving and summing PM and CM cost in $ for each affected component for each year of the study window.

    The majority of costs were retrieved from the MAXIMO database by the CARMA office in Denver and placed into a spreadsheet (Table FGM-2), where they were summed.

[28] See Data Collection and Costing Protocol - Maintenance Cost per Start/Stop in Appendix B.

4. Indexing maintenance costs to present value.

This was accomplished in Table FGM-2 using Consumer Price Index (CPI) data as follows:

CPI 2000 – 2011	
2000	172.2
2001	177.1
2002	179.9
2003	184.0
2004	188.9
2005	195.3
2006	201.6
2007	207.3
2008	215.3
2009	214.5
2010	218.1
2011	224.9

5. – 6. Finding the average annual increase in maintenance cost, C_{MI}.

This was accomplished in Table FGM-2, resulting in C_{MI} = $596.21. This is about 1% of the average annual maintenance in either of the two windows and, therefore, statistically insignificant. However, the remaining calculations are carried out to illustrate the method.

7. Determining the average annual number of increased start/stops N_{SS} from window 1 to window 2.

Using the operations data for Unit 1, the average annual number of starts from 2000-2005 was 35 and for 2006-2011was 113. The average annual increase N_{SS} was 78.

8. Calculating the Maintenance Cost per Start/Stop, $C_{M.}$

$$C_M = C_{MI} / N_{SS} = \$596.21 / 78 = \$7.64 \text{ per start/stop}$$

This figure needs to be adjusted to account for Unit 1 unit circuit breaker maintenance charged to common asset No. 13497. The indexed, average increase in unit circuit breaker maintenance for all three units between the two time windows was $56.99. Dividing this by 3 to estimate the cost for one unit and dividing by an N_{SS} of 78 finds the additional breaker start/stop cost to be $0.24 and this is added to C_M. C_M = $7.64 + $0.24 = $7.88

Maintenance Cost C_M = $8.00 per start/stop

Challenges / Caveats / Observations

1. That Unit 1 average annual maintenance costs did not increase in the second window is reasonable (the same result was found for Units 2 and 3). Maintenance expenditures are often driven largely by budgets and available staff. The number of staff dedicated to Flaming Gorge powerplant O&M has remained steady at approximately 11 FTE since at least 2003. With a fixed staffing level, maintenance cost increases are not likely over an extended period of time.

2. Also, the relationship between O&M budgets and potential increases in the amount of work initiated by increased start/stops is nebulous. In other words, increased start/stops may not raise O&M costs. In fact, EPRI finds, in an investigation of thermal plants, that cycling does not have a major impact on O&M costs, suggesting that other factors (e.g., staff-reduction strategies and changes in maintenance management strategies) may be more important in budgeting for O&M. [8] While this also may be true for hydro plants, more analysis of O&M cost trends may be warranted.

3. Another possible reason that maintenance costs did not increase is because there is a time delay between a period of increased start/stops (or any increased operation) and when maintenance increases and/or equipment deteriorates. An EPRI analysis of thermal plants found the delay between peak starts and peak forced outage rate is 7 to 10 years when the plant is newer and 3 to 4 years as the plant ages. [8] A similar delay should be expected for hydro units. In the Flaming Gorge analysis the higher start time window ended in 2011. After several more years of increased start/stops, maintenance may increase.

4. It should be noted that the historical data used in the analysis is problematic and may not reflect actual costs in all cases. Data from fiscal years starting in 2000 were retrieved and compared to later data. Flaming Gorge converted from the previous version of MAXIMO to the current CARMA version in 2008. The asset/location hierarchy was reorganized at that time and there was not always a one-to-one match between hierarchy elements.

5. Comparing the number of work orders between the two windows revealed that the average annual number of CM work orders dropped from 9.5 to 8.3. The average annual number of PM work orders increased from 52.5to 62.7. Overall, the average annual number of all work orders rose slightly from 62.0 to 67.5. Even though the number of work orders increased, overall maintenance costs did not.

6. As an automated plant, Flaming Gorge does not have any dedicated operators. Manual operations are conducted by dual-rated maintenance staff, as needed. Operations costs associated with maintenance work orders are charged to those work orders; thus, they collect O&M costs. When operators operate the units when no maintenance is in progress, they charge operations time to a standing (open) work order associated with the powerplant location (FG-PP) in MAXIMO. These operations costs are minimal.

7. The Flaming Gorge O&M data did not identify costs uniquely and directly attributable to start/stops, such as after-hours callout work needed to repair problems caused by increasing starts. At some plants, this cost may be significant, and the costs should be tracked in MAXIMO and included in the maintenance cost per start/stop.

8. Querying maintenance costs in the MAXIMO system is challenging. It requires significant understanding of how the asset/location hierarchy is constructed, how work is accomplished locally, and how costs are tracked.

   MAXIMO hierarchies are unique to each plant. When querying assets and locations for costs, care must be taken to ensure that all appropriate costs are included and that non-appropriate costs are excluded.

   Also, when one asset or location is used to capture costs for more than one unit, some form of prorating or estimating is required. This reduces the accuracy of the costing process. Unique assets or locations make costs easier to acquire.

   Finally, when PM tasks for multiple components are combined into one work order that is assigned to a high level in the hierarchy, identifying individual component costs is very difficult. As discussed above, PM on various components is accomplished under one work order assigned to location FG-PP-U1; segregating the costs for each component is impossible. While combining tasks may be logistically sound in managing work, it makes detailed cost tracking difficult.

Table FGM-2 - Flaming Gorge Unit 1 Maintenance Costs

LOCATION	FY	CM LABOR	CM MATERIALS	CM TOOLS	CM SRVS	CM TOTAL	PM LABOR	PM MATERIALS	PM TOOLS	PM SRVS	PM TOTAL	MAINT TOTAL
FG-PP-U1	FY00	5387.06	345.37	0	0	$5,732.43	19262.86	281.55	0	0	$19,544.41	
FG-PP-U1-BCW	FY00	217.84	27	0	0	$244.84	1796.16	7.21	0	0	$1,803.37	
FG-PP-U1-CW	FY00	543.84	0	0	0	$543.84	48.82	0	0	0	$48.82	
FG-PP-U1-EXC	FY00	453.75	0	0	0	$453.75	2544.1	201.6	0	0	$2,745.70	
FG-PP-U1-GEN	FY00	0	0	0	0	$0.00	7571.64	96.96	0	0	$7,668.60	
FG-PP-U1-GEN-COMP	FY00	0	0	0	0	$0.00	957.87	0	0	0	$957.87	
FG-PP-U1-GOV	FY00	0	0	0	0	$0.00	6252.42	164.28	0	0	$6,416.70	
FG-PP-U1-PROT	FY00	0	0	0	0	$0.00	1636.8	0	0	0	$1,636.80	
FG-PP-U1-TURBCOMP	FY00	2477.92	0	0	0	$2,477.92	0	0	0	0	$0.00	
TOTALS	FY00					$9,452.78					$40,822.27	$50,275.05
CPI	172.2											
INDEXED TOTALS	FY00					$12,345.70					$53,315.50	$65,661.20
FG-PP-U1	FY01	6736.48	1037.43	0	0	$7,773.91	10529.7	1792.44	0	0	$12,322.14	
FG-PP-U1-BCW	FY01	0	0	0	0	$0.00	1302.29	426.42	0	0	$1,728.71	
FG-PP-U1-CW	FY01	0	0	0	0	$0.00	585	0	0	0	$585.00	
FG-PP-U1-EXC	FY01	0	0	0	0	$0.00	2106.49	0	0	0	$2,106.49	
FG-PP-U1-GEN	FY01	0	0	0	0	$0.00	11335.42	0	0	0	$11,335.42	
FG-PP-U1-GEN-COMP	FY01	0	0	0	0	$0.00	554.79	0	0	0	$554.79	
FG-PP-U1-GOV	FY01	0	0	0	0	$0.00	5358.45	631.52	0	0	$5,989.97	
FG-PP-U1-PROT	FY01	0	0	0	0	$0.00	2916.49	0	0	0	$2,916.49	
FG-PP-U1-TURB	FY01	227.08	0	0	0	$227.08	0	0	0	0	$0.00	
FG-PP-U1-WTRWAY	FY01	56.77	0	0	0	$56.77	660.42	6224.31	0	0	$6,884.73	
TOTALS	FY01					$8,057.76					$44,423.74	$52,481.50
CPI	177.1											
INDEXED TOTALS	FY01					$10,232.58					$56,413.89	$66,646.47
FG-PP-U1	FY02	5446.03	6566.12	0	0	$12,012.15	17484.94	378.99	0	0	$17,863.93	
FG-PP-U1-AIRAD	FY02	1918.78	0	0	0	$1,918.78	0	0	0	0	$0.00	
FG-PP-U1-BCW	FY02	579.22	296.94	0	0	$876.16	2550.57	0	0	0	$2,550.57	
FG-PP-U1-CW	FY02	0	0	0	0	$0.00	479.12	0	0	0	$479.12	
FG-PP-U1-ELEC-XFMR	FY02	0	0	0	0	$0.00	31.42	0	0	0	$31.42	
FG-PP-U1-EXC	FY02	0	0	0	0	$0.00	814.63	0	0	0	$814.63	
FG-PP-U1-GEN	FY02	0	0	0	0	$0.00	6278.01	32.5	0	0	$6,310.51	
FG-PP-U1-GEN-COMP	FY02	0	0	0	0	$0.00	593.76	0	0	0	$593.76	
FG-PP-U1-GOV	FY02	0	0	0	0	$0.00	5572.5	344.43	0	0	$5,916.93	
FG-PP-U1-PROT	FY02	0	0	0	0	$0.00	1949.12	0	0	0	$1,949.12	
FG-PP-U1-WTRWAY	FY02	0	0	0	0	$0.00	3101.6	-3154.76	0	0	-$53.16	
TOTALS	FY02					$14,807.09					$36,456.83	$51,263.92
CPI	179.9											
INDEXED TOTALS	FY02					$18,510.92					$45,576.10	$64,087.02

FG-PP-U1	FY03	2316.53	5725.4	0	0	$8,041.93	2380.37	0	0	0	$2,380.37	
FG-PP-U1-AIRAD	FY03	1034.05	0	0	0	$1,034.05	0	0	0	0	$0.00	
FG-PP-U1-BCW	FY03	0	0	0	0	$0.00	0	418.92	0	0	$418.92	
FG-PP-U1-ELEC-XFMR	FY03	4080.26	3220.72	0	0	$7,300.98	91.08	95	0	0	$186.08	
FG-PP-U1-EXC	FY03	0	0	0	0	$0.00	1114.61	0	0	0	$1,114.61	
FG-PP-U1-GEN	FY03	0	0	0	0	$0.00	728.64	0	0	0	$728.64	
FG-PP-U1-GEN-COMP	FY03	122.5	0	0	0	$122.50	1009.3	0	0	0	$1,009.30	
FG-PP-U1-GOV	FY03	803.88	0	0	0	$803.88	361.53	75.36	0	0	$436.89	
FG-PP-U1-PROT	FY03	0	0	0	0	$0.00	1141.76	0	0	0	$1,141.76	
FG-PP-U1-TURB	FY03	242.02	0	0	0	$242.02	0	0	0	0	$0.00	
TOTALS	FY03					$17,545.36					$7,416.57	$24,961.93
CPI	184											
INDEXED TOTALS	FY04					$21,445.39					$9,065.14	$30,510.53
FG-PP-U1	FY04	3264.24	3323.33	0	31.77	$6,619.34	5045.32	0	0	0	$5,045.32	
FG-PP-U1-AIRAD	FY04	909.53	0	0	0	$909.53	0	0	0	0	$0.00	
FG-PP-U1-BCW	FY04	0	0	0	0	$0.00	2067.57	117.03	0	0	$2,184.60	
FG-PP-U1-CW	FY04	0	0	0	0	$0.00	288.53	0	0	0	$288.53	
FG-PP-U1-ELEC-XFMR	FY04	8199.58	1178.56	0	200	$9,578.14	0	0	0	283.14	$283.14	
FG-PP-U1-EXC	FY04	93.53	0	0	0	$93.53	1752.56	0	0	0	$1,752.56	
FG-PP-U1-GEN	FY04	0	0	0	0	$0.00	10650.97	247.86	0	0	$10,898.83	
FG-PP-U1-GEN-COMP	FY04	0	0	0	0	$0.00	580.79	163.36	0	0	$744.15	
FG-PP-U1-GOV	FY04	1333.28	0	0	0	$1,333.28	4211.46	290.26	0	0	$4,501.72	
FG-PP-U1-PROT	FY04	0	0	0	0	$0.00	2079.99	0	0	0	$2,079.99	
FG-PP-U1-TURBCOMP	FY04	0	0	0	0	$0.00	756.36	0	0	0	$756.36	
FG-PP-U1-WTRWAY	FY04	0	0	0	0	$0.00	532.52	465.04	0	0	$997.56	
TOTALS	FY04					$18,533.82					$29,532.76	$48,066.58
CPI	188.9											
INDEXED TOTALS	FY04					$22,065.94					$35,161.03	$57,226.97
FG-PP-U1	FY05	6419.35	202.03	0	14.75	$6,636.13	4771.97	0	0	0	$4,771.97	
FG-PP-U1-AIRAD	FY05	988.08	775.12	0	50.41	$1,813.61	0	0	0	0	$0.00	
FG-PP-U1-BCW	FY05	0	0	0	0	$0.00	2156.38	40.48	0	0	$2,196.86	
FG-PP-U1-CW	FY05	0	0	0	0	$0.00	356.76	1395	0	37.78	$1,789.54	
FG-PP-U1-ELEC-XFMR	FY05	2192.11	140.25	0	0	$2,332.36	84.75	0	0	0	$84.75	
FG-PP-U1-EXC	FY05	1042.49	0	0	0	$1,042.49	1262.9	0	0	0	$1,262.90	
FG-PP-U1-GEN	FY05	0	0	0	0	$0.00	8222.68	0	0	0	$8,222.68	
FG-PP-U1-GEN-COMP	FY05	0	0	0	0	$0.00	832.8	160.86	0	0	$993.66	
FG-PP-U1-GOV	FY05	0	0	0	0	$0.00	5374.76	570.96	0	0	$5,945.72	
FG-PP-U1-PROT	FY05	0	0	0	0	$0.00	2593.37	0	0	0	$2,593.37	
FG-PP-U1-TURBCOMP	FY05	0	0	0	0	$0.00	111.4	0	0	0	$111.40	
FG-PP-U1-WTRWAY	FY05	0	0	0	0	$0.00	2461.95	3986.25	0	163.79	$6,611.99	
TOTALS	FY05					$11,824.59					$34,584.84	$46,409.43
CPI	195.3											
INDEXED TOTALS	FY05					$13,616.74					$39,826.58	$53,443.32
AV ANN MAINT 00-05						$16,369.55					$39,893.04	$56,262.59

FG-PP-U1	FY06	2294.33	229	0	0	$2,523.33	2728.14	0	0	0	$2,728.14	
FG-PP-U1-AIRAD	FY06	47.45	0	0	0	$47.45	0	0	0	0	$0.00	
FG-PP-U1-BCW	FY06	142.35	0	0	0	$142.35	1328.13	61.2	0	0	$1,389.33	
FG-PP-U1-CW	FY06	0	0	0	0	$0.00	393.52	0	0	0	$393.52	
FG-PP-U1-ELEC-XFMR	FY06	50.28	0	0	0	$50.28	74.01	0	0	0	$74.01	
FG-PP-U1-EXC	FY06	0	0	0	0	$0.00	1233.97	0	0	0	$1,233.97	
FG-PP-U1-GEN	FY06	0	0	0	0	$0.00	2513.05	0	0	0	$2,513.05	
FG-PP-U1-GEN-COMP	FY06	491.9	0	0	0	$491.90	624.77	0	0	0	$624.77	
FG-PP-U1-GOV	FY06	0	0	0	0	$0.00	2322.46	511.44	0	0	$2,833.90	
FG-PP-U1-PROT	FY06	0	0	0	0	$0.00	2463.72	0	0	0	$2,463.72	
FG-PP-U1-TURB	FY06	819.35	0	0	0	$819.35	0	0	0	0	$0.00	
FG-PP-U1-TURBCOMP	FY06	0	0	0	0	$0.00	100.56	0	0	0	$100.56	
FG-PP-U1-WTRWAY	FY06	0	0	0	0	$0.00	81.94	0	0	0	$81.94	
TOTALS	FY06					$4,074.66					$14,436.91	$18,511.57
CPI	201.6											
INDEXED TOTALS	FY06					$4,545.59					$16,105.46	$20,651.05
FG-PP-U1	FY07	348.69	0	0	0	$348.69	1149.88	443	0	0	$1,592.88	
FG-PP-U1-BCW	FY07	0	2421	0	0	$2,421.00	104.46	0	0	0	$104.46	
FG-PP-U1-CW	FY07	0	0	0	0	$0.00	1196.96	0	0	0	$1,196.96	
FG-PP-U1-ELEC-XFMR	FY07	509.28	0	0	0	$509.28	101.52	0	0	0	$101.52	
FG-PP-U1-EXC	FY07	351.96	0	0	0	$351.96	841.32	0	0	0	$841.32	
FG-PP-U1-GEN	FY07	0	0	0	0	$0.00	76.38	0	0	0	$76.38	
FG-PP-U1-GEN-COMP	FY07	0	0	0	0	$0.00	835.12	331.44	0	0	$1,166.56	
FG-PP-U1-GOV	FY07	0	0	0	0	$0.00	229.49	137.69	0	0	$367.18	
FG-PP-U1-TURBCOMP	FY07	0	0	0	0	$0.00	24.6	0	0	0	$24.60	
TOTALS	FY07					$3,630.93					$5,471.86	$9,102.79
CPI	207.3											
INDEXED TOTALS	FY07					$3,939.20					$5,936.43	$9,875.63
FG-PP-U1	FY08	0	0	0	0	$0.00	1064.35	1197.47	0	124.59	$2,386.41	
FG-PP-U1-BCW	FY08	288.96	0	0	0	$288.96	361.2	0	0	0	$361.20	
FG-PP-U1-CW	FY08	6787.76	0	0	0	$6,787.76	228.41	0	0	0	$228.41	
FG-PP-U1-ELEC-XFMR	FY08	0	0	0	0	$0.00	203.46	0	0	0	$203.46	
FG-PP-U1-EXC	FY08	0	0	0	0	$0.00	3207.63	0	0	0	$3,207.63	
FG-PP-U1-EXC-VENT	FY08	0	0	0	0	$0.00	941.63	173.06	0	0	$1,114.69	
FG-PP-U1-GEN	FY08	0	0	0	0	$0.00	5027.61	949.94	0	23.94	$6,001.49	
FG-PP-U1-GEN-COMP	FY08	0	0	0	0	$0.00	6279.07	2220.85	0	0	$8,499.92	
FG-PP-U1-GOV	FY08	0	0	0	0	$0.00	2286.67	976.71	0	30.6	$3,293.98	
FG-PP-U1-INST	FY08	0	2720	0	0	$2,720.00	0	0	0	0	$0.00	
FG-PP-U1-PROT	FY08	0	0	0	0	$0.00	6363.31	0	0	0	$6,363.31	
FG-PP-U1-TURBCOMP	FY08	0	0	0	0	$0.00	249.09	0	0	0	$249.09	
FG-PP-U1-WTRWAY	FY08	0	0	0	0	$0.00	4990.29	115.99	0	0	$5,106.28	
TOTALS	FY08					$9,796.72					$37,015.87	$46,812.59
CPI	215.3											
INDEXED TOTALS	FY08					$10,233.55					$38,666.37	$48,899.91

FG-PP-U1	FY09	0	0	0	0	$0.00	777	0	0	0	$777.00	
FG-PP-U1-AG	FY09	478.71	0	0	0	$478.71	0	0	0	0	$0.00	
FG-PP-U1-BCW	FY09	1937.56	297.94	0	12.25	$2,247.75	2091.57	0	0	0	$2,091.57	
FG-PP-U1-CW	FY09	1984.75	202.68	0	9.5	$2,196.93	1192.06	0	0	0	$1,192.06	
FG-PP-U1-ELEC-XFMR	FY09	0	0	0	0	$0.00	600.37	0	0	238	$838.37	
FG-PP-U1-EXC	FY09	1174.46	0	0	0	$1,174.46	2043.34	0	0	0	$2,043.34	
FG-PP-U1-EXC-VENT	FY09	0	0	0	0	$0.00	814.19	19.4	0	0	$833.59	
FG-PP-U1-GEN	FY09	0	0	0	0	$0.00	19383.6	1160.19	0	15.75	$20,559.54	
FG-PP-U1-GEN-COMP	FY09	0	0	0	0	$0.00	1506.02	165.9	0	0	$1,671.92	
FG-PP-U1-GOV	FY09	254.97	817.75	0	14.25	$1,086.97	6458.06	364.01	0	0	$6,822.07	
FG-PP-U1-INST	FY09	1780.29	0	0	0	$1,780.29	0	0	0	0	$0.00	
FG-PP-U1-PROT	FY09	0	0	0	0	$0.00	6122.68	0	0	0	$6,122.68	
FG-PP-U1-TURBCOMP	FY09	3523.18	0	0	0	$3,523.18	174.66	0	0	0	$174.66	
FG-PP-U1-WTRWAY	FY09	0	0	0	0	$0.00	2764.35	0	0	0	$2,764.35	
TOTALS	FY09					$12,488.29					$45,891.15	$58,379.44
CPI	214.5											
INDEXED TOTALS	FY09					$13,093.78					$48,116.18	$61,209.96
FG-PP-U1	FY10	0	0	0	0	$0.00	3308.32	303.78	0	7.25	$3,619.35	
FG-PP-U1-BCW	FY10	0	0	0	0	$0.00	2375.37	0	0	0	$2,375.37	
FG-PP-U1-BRJA	FY10	3913.23	369.18	0	0	$4,282.41	0	0	0	0	$0.00	
FG-PP-U1-CW	FY10	566.37	0	0	0	$566.37	1430.6	2475	0	0	$3,905.60	
FG-PP-U1-ELEC-XFMR	FY10	0	0	0	0	$0.00	1576.73	0	0	10.4	$1,587.13	
FG-PP-U1-EXC	FY10	912.36	0	0	0	$912.36	2047.7	0	0	0	$2,047.70	
FG-PP-U1-EXC-VENT	FY10	0	936	0	0	$936.00	1034.15	28.44	0	0	$1,062.59	
FG-PP-U1-GEN	FY10	0	0	0	0	$0.00	23041.86	1565.2	0	104.75	$24,711.81	
FG-PP-U1-GEN-COMP	FY10	0	0	0	0	$0.00	3804.33	289.36	0	0	$4,093.69	
FG-PP-U1-GOV	FY10	0	0	0	0	$0.00	3107.15	330.01	0	0	$3,437.16	
FG-PP-U1-INST	FY10	0	0	0	0	$0.00	188.02	0	0	0	$188.02	
FG-PP-U1-PROT	FY10	0	0	0	0	$0.00	4424.69	0	0	0	$4,424.69	
FG-PP-U1-TURB	FY10	0	0	0	0	$0.00	2339.06	0	0	0	$2,339.06	
FG-PP-U1-TURBCOMP	FY10	5342.8	2954.84	0	0	$8,297.64	375.44	0	0	0	$375.44	
FG-PP-U1-WTRWAY	FY10	0	0	0	0	$0.00	2625.22	0	0	0	$2,625.22	
TOTALS	FY10					$14,994.78					$56,792.83	$71,787.61
CPI	218.1											
INDEXED TOTALS	FY10					$15,462.29					$58,563.54	$74,025.83
FG-PP-U1	FY11	0	0	0	0	$0.00	549.44	0	0	0	$549.44	
FG-PP-U1-BCW	FY11	0	0	0	0	$0.00	1809.11	324.9	0	12.92	$2,146.93	
FG-PP-U1-CW	FY11	0	0	0	0	$0.00	1044.84	0	0	0	$1,044.84	
FG-PP-U1-ELEC-XFMR	FY11	0	0	0	0	$0.00	14994.67	1404.18	0	0	$16,398.85	
FG-PP-U1-EXC	FY11	0	0	0	0	$0.00	358.96	0	0	0	$358.96	
FG-PP-U1-EXC-VENT	FY11	1057.3	0	0	0	$1,057.30	980.88	53.4	0	0	$1,034.28	
FG-PP-U1-GEN	FY11	11430.37	91.16	0	0	$11,521.53	30624.26	462.58	0	0	$31,086.84	
FG-PP-U1-GEN-COMP	FY11	27753.18	3035.32	0	0	$30,788.50	5895.36	348.16	0	0	$6,243.52	
FG-PP-U1-GOV	FY11	0	0	0	0	$0.00	11899.4	310.69	0	0	$12,210.09	
FG-PP-U1-INST	FY11	0	0	0	0	$0.00	182.6	0	0	0	$182.60	
FG-PP-U1-PROT	FY11	962.8	0	0	0	$962.80	4291.02	176.01	0	0	$4,467.03	
FG-PP-U1-TURB	FY11	0	0	0	0	$0.00	1118.79	47.69	0	0	$1,166.48	
FG-PP-U1-TURBCOMP	FY11	0	0	0	0	$0.00	362.79	79.94	0	0	$442.73	
FG-PP-U1-WTRWAY	FY11	0	0	0	0	$0.00	4759.5	68.15	0	0	$4,827.65	
TOTALS	FY11					$44,330.13					$82,160.24	$126,490.37
CPI	224.9											
INDEXED TOTALS	FY11					$44,330.13					$82,160.24	$126,490.37
AV ANN MAINT 06-11						$15,267.42					$41,591.37	$56,858.79
AV ANN INCREASE C_{MI}						-$1,102.12					$1,698.33	$596.21

Flaming Gorge Powerplant

Equipment Replacement Cost per Start/Stop

Objective

To determine the equipment replacement / rehabilitation start/stop cost C_R for Flaming Gorge Powerplant.

Discussion

Units 1,2, 3 Component	**Replacement / Rehabilitation History**
Generator stator/rotor/ field winding	Uprates 1991 - 1992
Unit Breaker	Replaced 1992
Exciter	Replaced 1990-1992
Governor	Original 1963-1964
Upper, Lower, and Thrust Bearings	Original 1963-1964
Turbine Guide Bearings	Replaced 2006-2008
Turbine Runner	Upgraded 2006-2008
Wear (Seal) Rings	Replaced 2006-2008

At the time of this report, Flaming Gorge had just finished rewedging the Unit 1 stator windings (approximate cost $150,000). Recent inspections show substantial loosening. The degree to which loosening had occurred roughly correlates to the relative number of increased start/stops in the last several years. For example, Unit 1 with the largest increase in number of start/stops in the second time window (225%) shows more loosening than Units 2 & 3 with 210% and 198% start/stop increases, respectively. However, Reclamation staff involved in the wedge analysis believe that much of the loosening is attributable to problems in the design or original installation. Even so, start/stops may be a contributing factor.

Even though the cost of stator winding replacement / rehabilitation is not considered in the initial calculation of start/stop costs, it is considered in the sensitivity analysis.

Method

For Flaming Gorge Unit 1, the generic protocol[29] for calculating equipment replacement costs was followed.

1. Determining the service-life average annual number of starts for the equipment. This is the typical number of starts expected or experienced annually by equipment over its expected life. This number has not yet been established in Reclamation but is assumed to be 35 for these calculations. In the Sensitivity Analysis portion of the study, the effect of assuming other values for this number is explored. Note that 35 happens to be the same number as the Unit 1 average annual starts in Window 1, the FY2000 – 2005 “normal” time window, but in general, the Window 1 number is not the same as the service-life annual number of starts.

2. – 3. Calculating the percent replacement cost from start/stop based on the EPRI 10-hours-per-start loss-of-life estimate.

Calculated as (35 x 10) / (8760 x .314) = 13%.[30] This value was placed in Table FGR-1.

4. Determining the Reclamation percentage replacement cost from start/stop.

At a site meeting at Flaming Gorge in March 2012, powerplant experts estimated the percentage replacement cost from start/stops for each component. These percentages were entered in Table FGR-1.

5. – 6. Calculating the annual cost in $ lost to start/stop and equipment replacement cost per start/stop of each component.

These calculations were made using the field-determined percentage replacement cost for each component and the 35 service-life average annual number of starts determined above. The results of these calculations were entered into Table FGR-1.

7. Summing the equipment replacement costs per start/stop for all components to arrive at the Equipment Replacement Cost per Start/Stop, C_R .

The result is shown in Table FGR-1.

Equipment Replacement Cost C_R = $145 per start/stop

Note that this calculation does not include the cost of stator winding replacement due to start/stop degradation. Such costs are addressed in the Sensitivity Analysis section of the report.

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[29] See Data Collection and Costing Protocol – Equipment Replacement Cost per Start/Stop in Appendix B.

[30] Flaming Gorge Average Plant Factor 2000-2006 is 31.4%. See Flaming Gorge Availability Cost protocol.

Challenges / Caveats / Observations

1. The major problem with calculating equipment replacement costs is estimating the degree of deterioration attributable to start/stop. The strategy used seems reasonable but is subjective.

2. Field forces made their estimates of Reclamation percent replacement costs based on expert knowledge and experience, with little reliance on the EPRI 10-hour- per- start loss-of-life estimate.

3. Field forces made their estimates of Reclamation percent replacement costs without much reliance on the tools listed in Table FGR-2. Although they believed the tools could be useful for this purpose, they felt that the tools were not sufficiently refined to add much value at this time.

4. The service-life average annual number of starts used in the calculations may not reflect the "normal" number of starts experienced by equipment over its service life. As shown in the Sensitivity Analysis, this number is very important to the equipment replacement cost and overall start/stop cost. At present, service lives are estimated in years, not in number of starts. The model requires that the service life be established in number of starts, as well.

5. The analysis includes only a select portion of Unit 1 equipment. If more equipment is included, the replacement cost per start/stop, C_R , will be higher.

6. As at most Reclamation plants, Flaming Gorge makes limited use of MCM. One capability that could be exploited exists in the SEL digital relay systems used for unit protection. They have a built-in, programmable unit circuit breaker wear indicator that counts operations and measures current flowing in each phase. Openings at load create higher wear than operations at no load. Cumulative effects are tracked by the relay system and could be used to measure breaker degradation.

7. The unit circuit breaker start/stop cost is a significant portion of the total start/stop cost. The circuit breaker is affected more directly by start/stops than any other component; closing and opening constitute the majority of wear and tear.

Table FGR-1 Flaming Gorge Unit 1 Equipment Replacement Cost per Start/Stop

EPRI % Replacement Cost From S/S = (Service-Life Average Annual Normal # Starts x 10) / (8760 x Plant Factor) = 35 x 10 / 2751 = 13%

Component	**Service Life (Yrs)**	**Total Replacement Cost[31] ($)**	**Annual Replacement Cost ($)**	**% Replacement Cost From S/S (EPRI)**	**% Replacement Cost From S/S (Reclamation)**	**Annual Cost From S/S at FG ($)**	**Replacement Cost per Start/Stop at FG ($)**
Field Winding	50	350,000	7,000	13	4	280	8.00
Unit Circuit Breaker	35	200,000	5700	13	70	3990	114.00
Excitation System	45	700,000	15,600	13	1	156	4.50
Governor	>50	500,000	<10,000	13	2	200	5.70
Turbine Runner	50	1,500,000	30,000	13	1	300	8.60
Thrust and Guide Bearings	>50	275,000	<5,500	13	1	55	1.60
Seal (Wearing) Rings	20	150,000	7500	13	1	75	2.15
Equipment Replacement Cost per Start/Stop, C_R							$145

[31] In 2011.

Table FGR-2 Flaming Gorge Unit 1 Equipment Loss of Life Analysis

	Diagnostic Testing	**PM/CM Measurements**	**hydroAMP Assessment**	**Failure Codes**	**MCM**	**Overall Maint. and Repl. Cost History**	
Component	Indicate degradation? Portion caused by start/stops?	Indicate degradation? Portion caused by start/stops?	Condition Index ≤ 6 ? Any Condition Indicators = 0, 1, or 2? Portion caused by start/stops?	Indicate degradation? Portion caused by start/stops?	Indicate degradation? Portion caused by start/stops?	Indicate degradation / replacement consistent with start/stops? Portion caused by start/stops?	**% Replacement Cost From S/S (Reclamation)**
Field Winding							
Unit Circuit Breaker							
Excitation System							
Governor							
Turbine Runner							
Thrust and Guide Bearings							
Seal (Wearing) Rings							

Data Collection and Costing

Flaming Gorge Powerplant

Water Energy Cost per Start/Stop

Objective

To determine the water-energy start/stop cost, C_{WE} , for Flaming Gorge Powerplant. Water energy is the amount of energy that could have been generated at full load with water used during a start.

Method

For Flaming Gorge, the generic protocol[32] for collecting water energy data and calculating water energy costs was followed.

1. V_T = 36,003 ft, as calculated in Flaming Gorge Water Commodity Data Collection and Costing procedure.

2. Flow rate Q_{FL} = 1540 ft^3/sec at full load, as measured with flowmeters by field forces.

3. – 4. The 2011 composite power rate is $29.62 per MWH.

$$C_{WE}(\$) = (V_T \times MW_{FL} \times \$/MWH) \ / \ (Q_{FL} \times 3600) =$$
$$(36{,}003 \text{ ft}^3 \times 50.65\text{MW} \times \$29.62) / (1540 \text{ cfs} \times 3600) = \$ \ 9.74$$

Water-Energy Cost C_{WE} = $10.00 per start/stop

Challenges / Caveats / Observations

1. The water energy cost is based on the assumption that the water used during a start could have been used to generate at full load. Whether or not this is a realistic assumption should be site-determined. This cost factor could be considered not applicable at some sites, or a reduced value that reflects less-than-full-load normal operation may be more appropriate.

[32] See Data Collection and Costing Protocol – Water-Energy Cost per Start/Stop in Appendix B.

Data Collection and Costing

Flaming Gorge Powerplant

Availability Cost per Start/Stop

Objective

To determine the availability start/stop cost C_A for Flaming Gorge Powerplant. These costs result from reduced generation lost to outages caused in part by increased start/stops.

Method

For Flaming Gorge, the generic protocol[33] for collecting availability data and calculating availability costs was followed.

1. – 3. Retrieving availability factors, calculating the average annual availability factor (AF) and average annual outage factor (OF) for each time window. Results are shown in Table FGA-1.

Table FGA-1

Flaming Gorge Unit 1 Availability / Outage Factors

Year	**Availability Factor (%)**
2000	94.93
2001	88.21
2002	86.61
2003	96.95
2004	95.05
2005	95.16
Average AF 2000-2005	92.82
Average OF 2000-2005 (100 – AF)	7.18
2006	97.13
2007	98.03
2008	37.62
2009	94.16

[33] See Data Collection and Costing Protocol – Availability Cost per Start/Stop in Appendix B.

2010	93.62
2011	89.23
Average AF 2006-2011	84.92
Average OF 2006-2011 (100 – AF)	15.08

This shows that the average outage factor more than doubled in the second (higher starts) window over the first (normal starts) window. The increase was due to more and longer scheduled outages. A more detailed analysis shows:

Window	Total No. / Length (hrs) Forced Outages	Total No. / Length (hrs) Scheduled Outages
2000-2005	5 / 109	23 / 3670
2006-2011	8 / 10	14 / 7740

4. Calculating the difference in average annual outage factor.

Difference in average annual OF = OF (2006-2011) - OF (2000-2005) =
15.08 – 7.18 = 7.30%

5. Calculating the difference in lost availability time in hours per year due to outages, T_A.

T_A = Difference in average annual OF x 8760 hours per year =
0.073 x 8760 = 639.5 Hrs / Year

6. Calculating the average annual MWH generation lost to unavailability.

MWH Loss = T_A x Unit 1 capacity MW_{Rated} =
639.5 Hrs/Yr x 50.65 MW = 32,391 MWH / yr

7. Calculating the average annual cost of unit unavailability in $.

The power rate used at Flaming Gorge in this calculation was determined by averaging the composite rates over the years 2006-2011, as shown in Table FGA-2.

Table FGA-2

Composite Power Rates

Year	**Rate (mills / KWH)**
2006	25.28
2007	25.28

2008	26.80
2009	29.62
2010	29.62
2011	29.62
Average 2006-2011	27.70

Average annual cost of unit unavailability = MWH Loss x power rate
= 32,391 MWH x $27.70 / MWH = $897,231

8. The average annual Unit 1 increase in number of start/stops between the two windows N_{SS} is 78, according to operations records.

9. Calculating the availability cost per start/stop, C_A.

   First, determine the average Plant Factor.

Flaming Gorge Plant Factor[34]	
Year	Plant Factor
2000	37.22
2001	20.32
2002	16.50
2003	17.78
2004	17.73
2005	26.07
2006	26.46
2007	22.21
2008	25.67
2009	31.22
2010	34.47
2011	48.34
Average 2006-2011	31.40

Availability Cost per Start/Stop, C_A ($) = [$T_A$ x MW_{Rated} x $ / MWH x Plant Factor] / N_{SS}
= $281,731 / 78 = $3612 per start/stop.

10. Adjust the availability start/stop cost to reflect actual start/stop impact.

[34] Plant factor % = (Gross Generation in MW x 100) / (Capacity in MW x 8760 hrs per year)

The calculated availability cost is unrealistically high because it assumes that all of the reduction in availability between the two windows is attributable to the change from “normal” operation to high start/stop operation.

The number and length of forced outages dropped between the two windows, which implies that equipment was not failing due to increased start/stops.[35] However, scheduled outage hours did increase, mostly due to Unit 1 turbine rehabilitation which took place in 2008. At 5480 outage hours, this was the longest single planned outage in any year in the 12-year Unit 1 study period. It included runner rehabilitation and replacement of guide bearings and seal rings.

There were no other Unit 1 major components replaced / rehabilitated in the 2006-2011 window. Therefore, the assumption was made to estimate how much of the reduced availability was due to turbine component start/stop wear and tear. To be consistent, the estimated start/stop degradation was assumed to be the same as estimated in the Flaming Gorge Equipment Replacement Data Collecting and Costing process. In that process, it was determined by field forces that the amount of turbine component deterioration due to start/stops is no more than 1% of total deterioration. Therefore, 1% was deemed appropriate for the adjusted availability calculation.

$$C_A = 1\% \text{ of } \$3612 = \$36.12 \text{ per start/stop.}$$

Availability Cost C_A = \$36 per start/stop

Challenges / Caveats / Observations

1. The adjustment factors used to arrive at the final availability cost are subjective, but logically derived and consistent with other costing methods in the study.

2. Forced outages resulting in reduced availability are time delayed by several years from initiation and peak of the increased start/stop period. Equipment failures will only result from an accumulation of many starts and hours of operation. An EPRI analysis of thermal plants found the delay between peak starts and peak forced outage rate is 7 to 10 years when the plant is newer and 3 to 4 years as the plant ages and that other factors, such as quality of maintenance, affect the forced outage rate. [8] Similar time delays should be expected in hydro applications.

[35] Even though overall corrective maintenance costs rose in the second window, CM may have been done during scheduled outages and not all CM applies to components affected by start/stops.

Data Collection and Costing

Flaming Gorge Powerplant

Opportunity Cost per Start/Stop

Objective

To determine the opportunity start/stop cost C_O for Flaming Gorge Powerplant. These costs result from generation lost due to the unit being held out of normal operation to provide increased non-spinning and replacement reserves.

Method

For Flaming Gorge, the generic protocol[36] for collecting opportunity data and calculating opportunity costs was followed. The method used compares net generation in MWH. The generic Opportunity Cost protocol also describes comparing net revenue as a way to account for shifting generation from peak to non-peak generation. However, this data was not available by unit at Flaming Gorge, therefore the net revenue method is not used here.

1. – 2. Retrieve net generation data and average net generation over the two time windows.

Operations records do not track net generation by unit at Flaming Gorge. Table FGO-1 summarizes annual plant net generation.

Table FGO-1

Flaming Gorge Plant Net Generation

Year (FY)	Net Generation (MWH)
2000	496.8
2001	268.5
2002	217.4
2003	233.9
2004	234.0
2005	344.4
Total 2000-2005	1,795
Average 2000-2005	299.2
2006	349.5

36 See Data Collection and Costing Protocol – Opportunity Cost per Start/Stop in Appendix B.

2007	292.8
2008	339.7
2009	413.0
2010	455.8
2011	640.9
Total 2006-2011	2,492
Average 2006-2011	415.3
Average 2000-2011	357.3

The portion of net generation delivered by Unit 1 was calculated by proration, using gross generation data:

Table FGO-2
Gross Generation By Unit (KWH)

Unit	**FY00-05**	**FY06-11**	**Total**
Unit 1	507.88 x 10^6	802.90 x 10^6	1,311 x 10^6
Unit 2	653.42 x 10^6	857.52 x 10^6	1,511 x 10^6
Unit 3	645.99 x 10^6	846.88 x 10^6	1,493 x 10^6
Total Unit 1-3	1,807.28 x 10^6	2,507.30 x 10^6	4,315 x 10^6

In FY00-05, the Unit 1 portion of the total gross generation was 28.1% and in FY06-11 it was 32.0%.

Applying these percentages to net generation results in:

Unit 1 Average Net Generation (FY00-05): 28.1% of 299.2 MWH = 84.08 MWH
Unit 1 Average Net Generation (FY06-11): 32.0% of 415.3 MWH = 132.90 MWH

3. Calculate the difference in average net generation between the two windows, MWH_D.

MWH_D = Average Net (2000-2005) - Average Net (2006-2011)
= 84.08 – 132.90 is < 0

It is clear that net generation in the high start/stop window was greater than net generation in the "normal" start/stop window. That is, more start/stops did not decrease the opportunity to generate.

The remaining calculations are carried out to demonstrate the method.

4. Calculate the total opportunity cost between the two time windows.

   The revenue rate used at Flaming Gorge in this calculation was determined by averaging the composite rates over the years 2006-2011, as shown in Table FGO-3.

Table FGO-3

Composite Revenue Rates

Year	**Rate (mills / KWH)**
2006	25.28
2007	25.28
2008	26.80
2009	29.62
2010	29.62
2011	29.62
Average 2006-2011	27.70

The total opportunity cost = MWH_D x \$ / MWH = 0 MWH x \$27.70 = \$0

5. The average Unit 1 increase in number of start/stops between the two windows N_{SS} is 78, according to operations records.

6. Opportunity Cost per Start/Stop:

   C_O (\$) = [MWH_D x \$ / MWH] / N_{SS} = \$0 / 78 = \$0 / per start stop.

Opportunity Cost Co = \$0 per start/stop

Challenges / Caveats / Observations

1. Net generation increased during the high start/stop window over the “normal” window. Even though starting and stopping units more frequently would seem likely to reduce the opportunity to generate at load, there are other factors that make the increase in generation more understandable. The plant factor for Flaming Gorge shows that the plant

has plenty of capacity for increased starts AND more generation. It is not a question of trading off one for the other.

2.

Table FGO-4
Flaming Gorge Plant Factor[37]

Year	Plant Factor
2000	37.22
2001	20.32
2002	16.50
2003	17.78
2004	17.73
2005	26.07
2006	26.46
2007	22.21
2008	25.67
2009	31.22
2010	34.47
2011	48.34

In fact, when analyzing hydro plant reliability costs, EPRI states "Because of the typically low value of service factors encountered in pump/turbine unit operation, assessment of losses on the basis of loss of production is not justifiable for these units." [9]

Also, there is a tendency by power system operators to leave a unit on line, once it has been started and connected. Thus, there is actually more opportunity to generate.

It seems likely that this same phenomenon – increased starts with increased generation – is likely at other facilities, and thus it may be difficult to find any opportunity costs except where there is a real tradeoff between starts and continuous running. However, at plants where units are completely removed from running at load for any length of time and are now only used for starting with short running time, it may be possible to find measurable opportunity costs.

3. If net revenue data had been available by unit, it would be possible to assess whether increased starts shifted generation from peak to non-peak periods. If so, an opportunity cost would result. Collecting net revenue data would be a way to improve calculations of this cost factor at this and other plants.

[37] Plant factor % = (Gross Generation in MW x 100) / (Capacity in MW x 8760 hrs per year)

Data Collection and Costing

Flaming Gorge Powerplant

Efficiency Cost per Start/Stop

Objective

To determine the efficiency start/stop cost C_E for Flaming Gorge Powerplant. Efficiency reduction results from increased turbine runner cavitation caused by increased start/stops.

Method

For Flaming Gorge, the generic protocol[38] for collecting efficiency data and calculating efficiency costs was followed. The efficiency cost consists of two components: the commodity cost and opportunity cost of water lost to reduced efficiency.

A constant head was assumed for all calculations.

Commodity

1. Determining the percentage loss of turbine efficiency to date from field measurements.

The Flaming Gorge turbine runners, originally installed in 1963, were replaced in 2006-2008. Efficiency measurements were not taken on the old runners before replacement. Therefore, the actual percent efficiency loss over the service life is unknown. Reclamation rarely makes such measurements on runners ready for replacement. Therefore, a reasonable estimate must be made, with the possibility that future research in turbine efficiency loss may provide a more accurate number.

Performance measurements showed a 5%-6% increase in efficiency, comparing the new runners to the original efficiency data on the old runners. It may be reasonable to use 5% as a first estimate of loss of efficiency, so this figure was used in the following calculations.

2. Estimating the percentage of the above efficiency loss attributable to start/stops.

The estimate used for the runner was 1% which, for consistency, was taken from the Equipment Replacement Cost protocol for Flaming Gorge.

3. Calculating the start/stop efficiency loss percentage:

Start/Stop % Efficiency Loss = % Total Efficiency Loss x % Estimated Loss from Start/Stop

[38] See Data Collection and Costing Protocol – Efficiency Cost per Start/Stop in Appendix B.

$$= 5\% \times 1\% = 0.05\%$$

4. Acquiring the flow rate in cfs at full load. Calculating the total flow in cfs per MWH:

From flowmeter readings, flow at full load Q_{FL} = 1540 cfs @ 419 ft head.

$$Q_T\ (ft^3/MWH) = Q_{FL} \times 3600 / MW_{Rated} = 1540 \times 3600 / 50.65MW = 109{,}457\ ft^3/MWH$$

5. Finding the flow per MWH due to start/stops.

$$Q_{SS}\ (ft^3/MWH) = Q_T \times \text{Start/Stop \% Efficiency Loss} = 109{,}457 \times 0.05\% = 54.7ft^3/MWH$$

6. Acquiring the average annual total energy produced in MWH. Finding the annual volume of water used in one year for start/stops.

Net generation by unit is not recorded at Flaming Gorge. However, from Table FGO-1 of the Flaming Gorge Opportunity Cost calculations, the plant average annual net generation from FY2000-FY2011 was 357.3 MWH. Unit 1 gross generation during this time period was 30.4% of the total plant gross generation. Applying this percentage to the net generation figure yields an average annual net generation for Unit 1 of 108.6 MWH.

$$V_{SS}\ (ft^3) = MWH_{Annual} \times Q_{SS} = 108.6\ MWH \times 54.7\ ft^3/MWH = 5940\ ft^3$$

7. Calculating the efficiency commodity cost per start/stop, C_{EC}.

From operations records, the average annual number of Unit 1 starts 2006-2011 was 113.

$$\begin{aligned} C_{EC} &= (V_{SS} / 43{,}560\ ft^3 \text{ per AF}) \times \$/AF \ / \ \text{Av. Annual \#Starts} \\ &= (5940 / 43{,}560) \times \$85 \ / 113 \\ &= \$0.10 \text{ per start/stop} \end{aligned}$$

This number was adjusted by dividing by 2.4, using the logic specified in the generic protocol, to correct for increasing deterioration over time, resulting in:

$$C_{EC} = \$0.04 \text{ per start/stop}$$

Opportunity

1. Acquiring the average annual net generation. Calculating the annual lost generation in MWH lost to start/stop efficiency loss.

The average annual net generation for Unit 1 is 108.6 MWH, as determined in step 6 of the lost commodity methodology, above.

The start/stop % efficiency loss is 0.05 % as found in step 3 of the lost commodity cost methodology, above.

Annual generation loss from start/stop efficiency loss (MWH) =
Average annual net generation (MWH) x Start/Stop % Efficiency Loss
= 108.6 MWH x 0.05% = 0.054MWH

2. Calculating the efficiency lost-opportunity cost per start/stop, C_{EO}.

The average composite power rate 2006-2011 was \$27.70 / MWH for Flaming Gorge and the average annual number of starts for this period was 113.

C_{EO} (\$) = Annual generation loss (MWH) x \$/MWH / Av. Annual # Starts
= 0.054 MWH x \$27.70 / 113 = \$6.14

This number was adjusted by dividing by 2.4, using the logic specified in the generic protocol, to correct for increasing deterioration over time, resulting in:

C_{EO} = \$2.56 Per start/stop

Total Efficiency

Calculating the efficiency cost C_E per start/stop:

$C_E = C_{EC} + C_{EO}$
= \$0.04 +\$2.56 = \$2.60 per start/stop

Efficiency Cost C_E = \$3.00 per start/stop

Challenges / Caveats / Observations

1. The calculations are hampered by the lack of data on actual turbine efficiency reduction over the service life. The estimate used is a reasonable starting place and can be adjusted as more becomes known about turbine loss of efficiency.

2. The % loss of efficiency attributable to start/stops is consistent with that used in the Equipment Replacement protocol, but is subjective.

3. The method of adjusting the efficiency cost for the varying rate of deterioration is speculative.

Data Collection and Costing

Flaming Gorge Powerplant

Water Commodity Cost per Start/Stop

Objective

To determine the water commodity start/stop cost C_{WC} for Flaming Gorge Powerplant. Water commodity costs result from inability to sell water used for start/stops.

Method

For Flaming Gorge, the generic protocol[39] for collecting lost water commodity data and calculating lost water-commodity costs was followed.

Times and flows were taken from the sequence-of-events recorder and flowmeters by field personnel at Flaming Gorge. Times are averages over several starts.

Start to SNL

1. Determining the volume of water used to bring the unit from stop to synchronism.

T_{SN} = 20 sec.
Q_{NL} = 99 cfs.

$V_{SN} = T_{SN} \times Q_{NL} = 20 \times 99 = 1980 \text{ ft}^3$

SNL to Synchronism

2. Determining the volume of water used to keep the unit at SNL until synchronism.

T_{NS} = 45 sec.
Q_{NL} =99 cfs.

$V_{NS} = T_{NS} \times Q_{NL} = 45 \times 99 = 4455 \text{ ft}^3$

Synchronism to Load

3. Determining the volume of water lost to inefficient operation during ramping from synchronized on line to 50% load, V_{RU}, where the most efficient part of the turbine efficiency curve begins.

[39] See Data Collection and Costing Protocol – Water Commodity Cost per Start/Stop in Appendix B.

The ramping rate is 10% per minute. Using the Flaming Gorge turbine efficiency and flow curves in Figure FGWC-1, the average efficiency, E_A, between 50% load and full load is approximately 93%. The volume of water lost to inefficiency at 10%, 20%, 30%, 40%, and 50% load are:

$V_{I10} = (E_A – E_{I10})$ x Q_{I10} x 60 sec/min = (0.93-0.62) x 240 cfs x 60 = 4464 ft^3
$V_{I20} = (E_A – E_{I20})$ x Q_{I20} x 60 sec/min = (0.93-0.76) x 380 cfs x 60 = 3876 ft^3
$V_{I30} = (E_A – E_{I30})$ x Q_{I30} x 60 sec/min = (0.93-0.83) x 520 cfs x 60 = 3120 ft^3
$V_{I40} = (E_A – E_{I40})$ x Q_{I40} x 60 sec/min = (0.93-0.88) x 640 cfs x 60 = 1920 ft^3
$V_{I50} = (E_A – E_{I50})$ x Q_{I50} x 60 sec/min = (0.93-0.90) x 780 cfs x 60 = 1404 ft^3

Volume of water lost to inefficiency during ramp up, V_{RU}:

$V_{RU} = V_{I10} + V_{I20} + V_{I30} + V_{I40} + V_{I50}$ = 14,784 ft^3

Load to No Load

4. Determining the volume of water lost to inefficient operation during ramping down from 50% load to no load, $V_{RD.}$

The ramp down rate is assumed the same as the ramp up rate of 10% per minute, thus $V_{RD} = V_{RU}$ = 14,784ft^3.

Total Lost Water

5. Determining the total volume of lost water in cubic feet during the start.

$V_T = V_{SN} + V_{NS} + V_{RU} + V_{RD}$ = 1980 + 4455 + 14,784 14,784 = 36,003 ft^3

6. Determining the cost of water in cubic feet.

Water at Flaming Gorge is valued at approximately $85 / acre-ft[40]

$ / ft^3 = $ per acre-foot / 43,560 = $85 / 43,560 = 0.002 $/$ft^3$

7. Determining the Water Commodity Cost, C_{WC} by multiplying V_T by $ / ft^3

Water Commodity Cost per Start/Stop, C_{WC} ($) = V_T x $ / ft^3
= 36,003 cu ft. x 0.002 $/$ft^3$ = $72.00

[40] Approximate 2011 CRSP municipal & industrial (M&I) short-term rate.

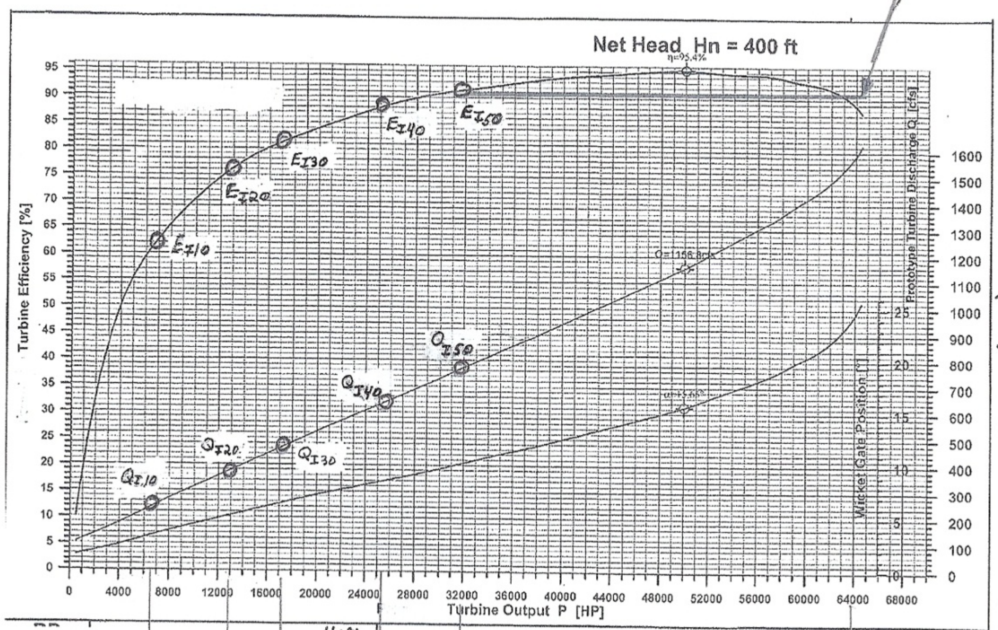
Water Commodity Cost C_{WC} = \$72.00 per start/stop

Challenges / Caveats / Observations

1. The water commodity cost may not be applicable to start/stop costs, depending on how water is valued and marketed at a project.

Figure FGWC-1
Flaming Gorge Turbine Efficiency Curve

Average Efficiency
$E_A = 93\%$



40%

10% 20% 30% 50%

Full Load

$E_{I10} = 62\%$
$Q_{I10} = 240cfs$

$E_{I20} = 76\%$
$Q_{I20} = 380cfs$

$E_{I30} = 83\%$
$Q_{I30} = 520cfs$

$E_{I40} = 88\%$
$Q_{I40} = 640cfs$

$E_{I50} = 90\%$
$Q_{I50} = 780cfs$