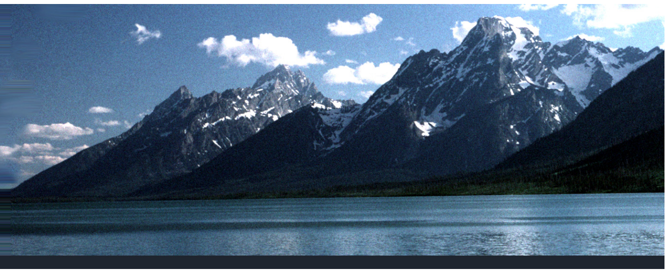
Rocky Mountain Econometrics
208-344-0809
208-631-4334 Cell
P.O. Box 1914
Boise, ID. 83701
tjones@design4000.net
www.rmecon.com
Anthony Jones - Principal



CRITIQUE OF THE Goldendale Energy Storage Hydroelectric Project (FERC No. 14861) NOTIFICATION OF INTENT

Prepared for

American Rivers

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Anthony Jones
ROCKY MOUNTAIN ECONOMETRICS
www.rmecon.com

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I. EXECUTIVE SUMMARY

- On January of this year, 2019, FFP Project 101, LLC, notified FERC of its intent to file an application for an original license for the Goldendale Energy Storage Project No. 14861 (Goldendale), a closed-loop pump storage project, in Washington State close to the Columbia River near to the John Day Dam.[1]

- In the Notice of Intent (NOI) Goldendale's stated purpose for the project is that:
  - "Within the region, renewable energy development is growing, primarily through wind power generation. The Project would provide necessary ancillary services and energy storage to the Northwest region, and allow for more reliable management and integration of disparate renewable energy sources into the grid. The Project would provide additional ramping capacity (both up and down) as well as firming for wind energy regulation, coordination, and scheduling services, automatic generation control, and support of system integrity and security (reactive power, spinning, and operating reserves)."[2]
  -
- Rocky Mountain Econometrics (RME) finds that while the project may be technically able to serve in the stated capacity for a portion of each day, it will not be able to serve in that capacity for a large portion of each day when its upper reservoir has been partially or wholly used for power production and needs to be refilled. It is also extremely unlikely that Goldendale will be financially viable.

- While Goldendale's description of project operations are preliminary in nature and not overly detailed, the parameters of pump storage project operations are well understood, Goldendale's construction costs are sufficiently well defined, and the wholesale energy environment in which it will operate are clear. As a result RME is able to conclude that the Goldendale project is very unlikely to operate profitably given the state of current and future west coast and northwest energy pricing.

- As briefly as possible, Goldendale's challenge is that to service its debt and cover the cost of M&O, as well as the cost of filling its supply reservoir as a prerequisite to generate power, Goldendale will have to charge almost double the going rate of peak hour open market (NP15) energy. Worse, since pump storage project sales hours are necessarily restricted to the portion of the day when the upper reservoir is not being filled, the opportunity to absorb overhead by operating more than about eight hours per day is precluded. Finally, while Goldendale's costs of operation will likely increase with inflation over time, NW energy prices for the past two decades have been flat or declining as the market transforms to accommodate proportionally larger and larger amounts of solar power, a trend that is destined to continue.

[1] Goldendale Energy Storage Hydroelectric Project, (FERC No. 14861), Klickitat County, Washington, NOTIFICATION OF INTENT, Prepared for FFP Project 101, LLC.
[2] Ibid., pp. 2.

II. PROJECT DESCRIPTION

From Goldendale's NOI: Goldendale Energy Storage Project FFP Project 101, LLC, FERC Project No. 14861 Page 4 January 2019

> The Project area has the suitable geography for a closed-loop pumped storage facility and is strategically located at the northern terminus of the Pacific AC and DC Interties operated by BPA, Los Angeles Department of Water & Power, and the California Independent System Operator (CA-ISO).
>
> The interties allow for the bulk seasonal exchanges of power between British Columbia, Canada, the Northwest, and California and provide benefits of coordinated markets to the regions.
>
> The Project is also located in close proximity to substantial existing, abundant, high quality, and untapped wind power generation that can be developed with relatively low environmental conflict and cost. The Project's location can also support the daily inter-regional exchanges of California massive mid-day solar oversupply and the significant power generation ramping needed by CA-ISO.3
>
> The proposed Project is a closed-loop pumped storage hydropower facility located off-stream of the Columbia River at John Day Dam, located on the Washington (north) side of the Columbia River at River Mile 215.6. The Project will be located approximately 8 miles southeast of the City of Goldendale in Klickitat County, Washington.
>
> The proposed Project will involve no river or stream impoundments, allowing for minimal potential environmental impact. Initial fill water and periodic make-up water will be purchased from Public Utility District No. 1 of Klickitat County, Washington (KPUD) using a KPUD-owned conveyance system and municipal water right.
>
> The Project facilities include:
> • _An upper reservoir consisting of a rockfill embankment dam approximately170 feet high, 8,000 feet long, a surface area of about 59 acres, storage of 7,100 acre-feet (AF), at an elevation of 2,940 feet above mean sea level (AMSL);
>
> • _A lower reservoir consisting of an embankment approximately 170 feet high, 7,400 feet long, a surface area of about 62 acres, storage of 7,100 AF, and an elevation of 580 feet AMSL.
>
> • _An underground water conveyance tunnel and underground powerhouse; and
>
> • _230-kilovolt (kV) transmission line(s).
>
> The rated (average) gross head of the Project is 2,400 feet, and the rated total installed capacity is 1,200 megawatts (MW).

[3] Ibid., pp. 4.

Project Characteristics

Approximate Installed Capacity	1,200 MW
Assumed Number of Units (Variable Speed)	3
Assumed Average Static Head	2,360 feet
Assumed Usable Storage Volume	7,100 AF
Approximate Energy Storage	14,745 MWh
Approximate Hours of Storage @ 1,200 MW	12 hours

Underground Powerhouse

Rated Head (Gross)	Approximately 2400 feet
Max Flow Generating Mode	8,280 cfs
Max Flow Pumping Mode	6,700 cfs
Generating Capacity	Up to 1,200 MW
Number of Units	3 x 400 MW units

III. MARKET PRICES

Understanding Goldendale requires understanding the west coast wholesale energy market with which it will interface.

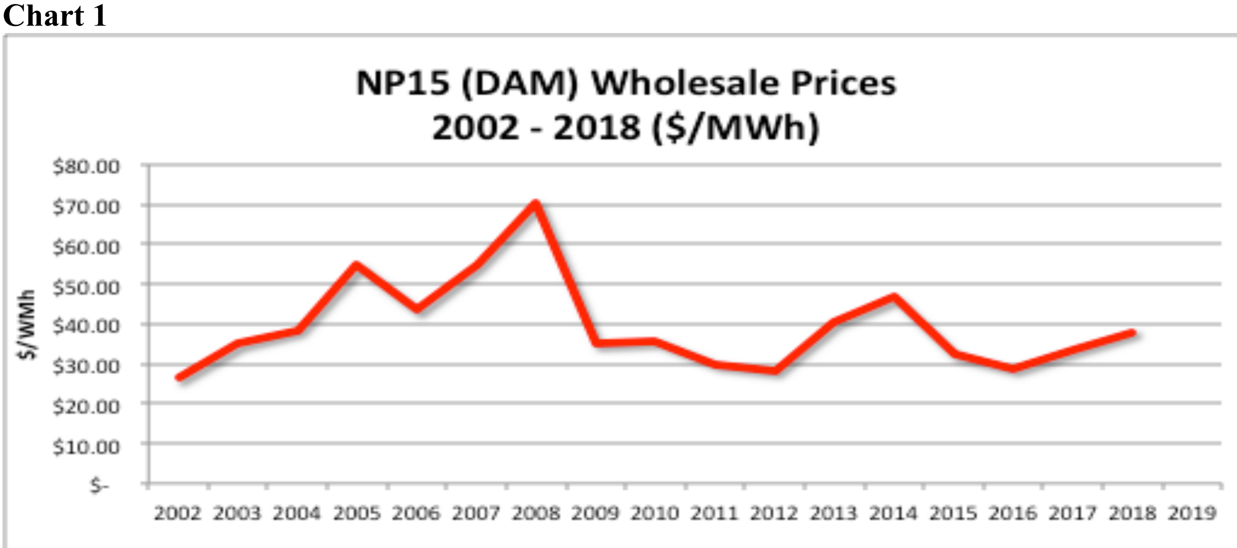
Unlike many, perhaps most, pump storage projects that are built in conjunction with a relatively fixed output, often thermal, generating station, Goldendale will be a free standing, independent operation buying and selling power on the western transmission grid, from and to the west coast wholesale energy markets.

The NOI talks broadly about supporting other regional power producers but makes no mention of contracting with any of them. For the purposes of this analysis RME assumes Goldendale will be a freelance operation, attempting to buy low and sell high on the wholesale market, to the extent of their ability, at their discretion. In the absence of contractual requirements for energy used to fill their upper reservoir or sell their production, it is to market prices that we must look to understand the forces that will shape Goldendale's potential for success or failure.

Pre 2009, Prelude to a Crash

In the years leading up to 2009, west coast and northwest wholesale energy prices were escalating rapidly. From 2002 through 2008, NP15 prices climbed from about $25/MWh to over $70/MWh, a 180 percent increase in a scant six years. In 2008, FERC, BPA, and most NW utilities were predicting energy prices to continue escalating, at a somewhat slower rate, on upward toward $80, $90, and $100/MWh within 10 years.

Chart 1



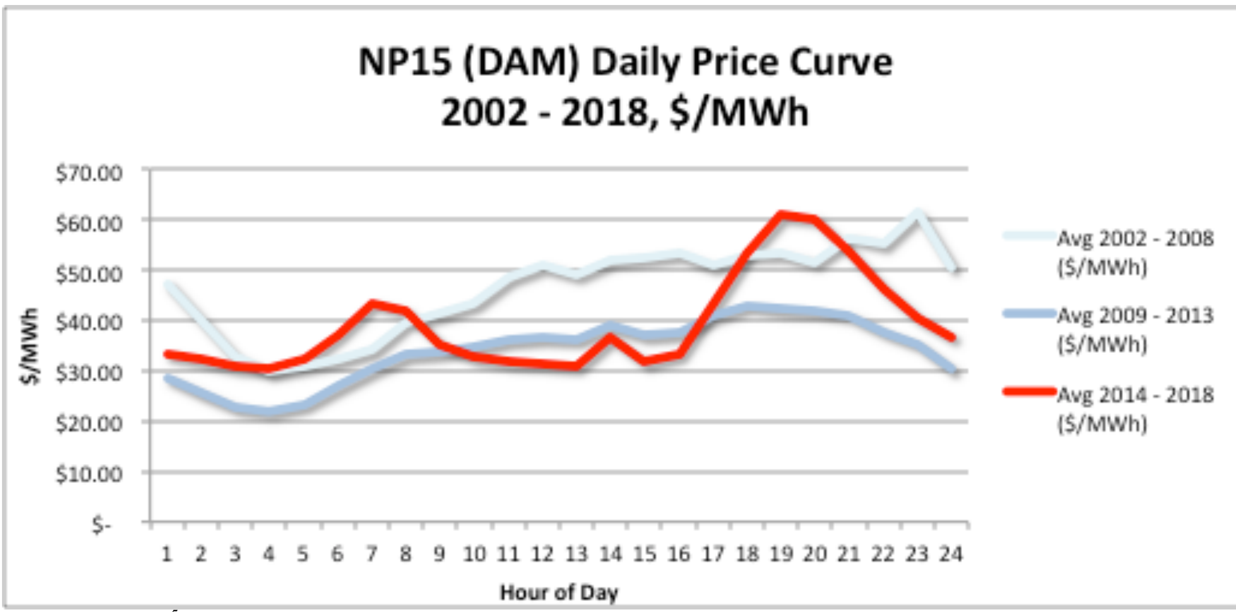
Source: CAISO[4]

[4] http://oasis.caiso.com/mrioasis/logon.do

That line of thinking collapsed in 2009, the first year of the Great Recession. That year saw the collapse of gas prices (a major factor in the price of power produced by gas generating plants) and the point where solar capacity in California started gaining traction. In one year, from 2008 to 2009, NP15 prices dropped by 50 percent and have never recovered to any substantive degree for more than a year or two. Nine years after the 2009 price collapse 2018 prices averaged about $38/MWh, roughly half of price levels ten years previous. And, the 2018 number would likely have been lower still if not for the effect of the Camp Fire in California that took several major PG&E generating plants offline for several months of the year, thus reducing supply and driving prices higher. Please refer to Chart 1, above.

Prices from 2009 to 2013 followed a daily price curve similar to but lower than the daily price curve prior to 2009. Daily prices continued to bottom out in the hours from midnight to about 6:00 AM and then began climbing to a peak in the late afternoon or early evening. Where pre 2009 prices bottomed out at about $30/MWh, post 2008 prices bottomed out about $10 lower at $20/MWh. Where pre 2009 prices topped out as high as $60/MWh in the late evening, post 2008 prices topped out about $20 lower at about $42/MWh as early as 6:00 PM.

Chart 2



Source: CAISO[5]

Prior to 2009 the range from minimum to maximum price for the day averaged a little more than $30/MWh. From 2009 - 2014 the daily average price range from minimum to maximum was about $8 less, at roughly $22/MWh. Please see Chart 2, above.

[5] http://oasis.caiso.com/mrioasis/logon.do

The lower overall prices and the narrowing of total price range after 2008 was probably due to a combination of factors including reduced demand due to the recession, lower gas prices used by thermal generating plants, and the beginnings of the solar power revolution associated with California investing in renewable energy.

High Spot Market Prices May Not Be Enough

If Goldendale would have made this proposal back in 2008, the year before market prices collapsed from the $70/MWh range or higher, it would be more difficult to find fault with the proposal. Even the most respected forecaster has difficulty selling an audience on the likelihood of $30 market prices when they looking at prices averaging as much as $80/MWh for months at a time.

But this is not 2008 and prices have not averaged greater than $50/MWh on an annual basis in ten years. In fact, the price collapse was fully expected. The precipitousness of the decline might seem a little severe but the price correction was completely normal. High prices, while inconvenient, are the mechanism that triggers innovation and investment in the market. They lead to new construction that results in more capacity, greater supply, and ultimately lower prices.

The run-up to 2008 was not the first of its kind and is unlikely to be the last. Similarly, price corrections such as the one in 2009 are equally as normal as the preceding price spike. It is for that reason that RME cautions against any prophesy that market prices will return to pre 2009 levels for anything more than brief periods. As Chart 1 demonstrates, 2013-2014 looked like prices were once again heading towards pre 2009 $60 and $70 levels. But, again, price changes of that nature are the events that trigger new investment, more construction, and more supply that drives prices back down to $30/MWh and lower.

One final point before leaving the subject of pre-2009 high market prices. As we will see, high prices are a necessary condition for Goldendale to cover their costs construction costs, but not a sufficient condition for to cover their operating costs.

High peak hour prices are little benefit to pump storage projects if it means similarly high off-peak hour prices. Projects of this nature also need situations that increase the spread between high and low daily prices. Years like 2008 when average prices were much higher than after 2009 present a situation in which the daily price spread is potentially higher, but not necessarily as high as needed.

Emergence Of The Duck Curve

Even more significant for this discussion is the transformation of the western energy market that started in about 2014. That year marked the emergence of the "Duck Curve". The Duck Curve, named for the curve's late in the day resemblance to the profile of a duck's head, is the result of solar power becoming a major force in the California energy market.

Starting in 2014 prices from about 3:00 AM to about 8:00 AM returned to or even exceeded pre 2008 price levels, the difference being that by about 9:00 solar energy sources stared producing in sufficient volume that prices, instead of continuing to increase, dropped back to pre-dawn levels of about $30/MWh where they remained until about 5:00 PM when the late in the day peak begins. As with the morning peak, the late day peak is as high or higher than the pre 2009 peak but it is much shorter in duration. Again, please refer to Chart 2, above.

Dual Daily Supply Curves

Classical economic theory holds that as demand increases, it shifts the demand curve to the right and the equilibrium price increases. At first glance that result would seen to be violated in the western wholesale energy markets where midday prices are now typically lower than earlier in the day even though the amount of energy demanded is substantially higher. However, the west coast currently operates with, effectively, two supply curves, a nighttime curve and a daytime curve.

Early in the day, in the first few hours of peak demand before sun-up, energy load begins to ramp up and, with the nighttime supply curve in play, prices begin to rise in response. Later in the morning, with load ramping up even further, the supply curve begins to shift to the right as solar generation comes online. This process not only counters the earlier increase in prices but also typically over-compensates and drives prices lower than they were before the sun rises.

It is this price environment in which Goldendale proposes to operate. In an effort to recharge the upper reservoir during the 10 lowest cost hours of the day, Goldendale will have to pump for five hours from about midnight to 5:00 AM, for another four hours from about 10:00 AM to about 1:00 PM, and finally for one hour at 3:00 PM.

About half of Goldendale's pumping will occur during the relatively low priced but high load middle of the day.

In an effort to sell power during the 8 highest hourly prices of the daily load and price cycle, Goldendale will need to run its generators for an hour during the morning price peak at about 7:00 AM, and for 7 hours from about 5:00 PM through 11:00 PM. Please see Chart 3 below.

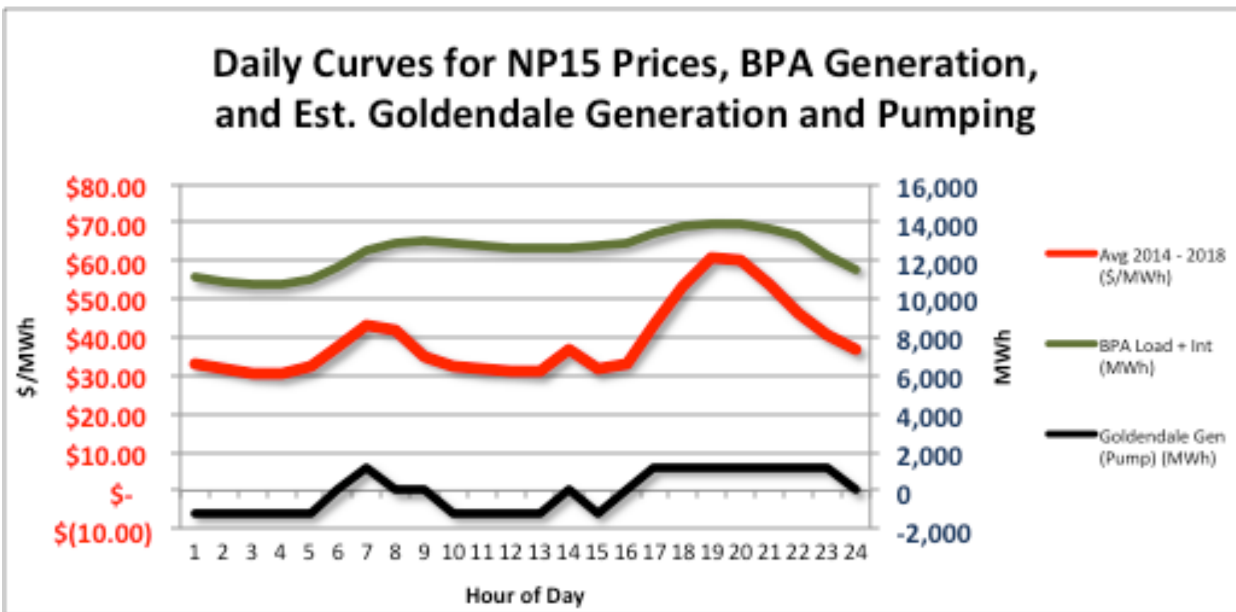
One final takeaway for the post 2008 open market price history is that inflation has been outpacing NP15 prices and that the difference between peak prices and off peak prices, as constrained by Goldendale's profit maximizing operation curve, is a relatively stable $16 - $18/MWh.

For the purpose of this analysis of Goldendale's finances, RME will use the 2014 – 2018 minimum and maximum prices of $32.0475 and $50.2530 respectively. The reason for using these two numbers is that it provides a slightly greater range in prices than the full 2009 – 2018 record provides, a factor that gives the benefit of doubt to Goldendale in recognition that they may bring more sophisticated modeling to the operation than RME has at its disposal.

NP15 Prices

	Avg. Minimum Prices	Avg. Minimum Prices	Avg. Price Spread
2014 - 2018	$32.0475	$50.2530	$18.2055
2009 - 2018	$29.5999	$45.9677	$16.3679

Chart 3



IV. GOLDENDALE FINANCIALS

The Goldendale NOI estimates that the project will cost $2.2 billion. The inclusion of Washington State sales tax and capitalized pre-completion interest will bring the startup cost of the project to about $2.6 billion. Servicing the interest on $2.6 billion will cost Goldendale about $208 million per year.

The NOI indicates that M&O costs will come to about 8.5 million per year, bringing the total for debt service and M&O to about $216 million per year, roughly $62/MWh without accounting for pumping costs.

Goldendale - With Amortization

Capital Cost		
PAD Cost Estimate	$2,200,000,000	1
WSST @ 6.5%	$143,000,000	2
Total Estimated Direct Cost	$2,343,000,000	
Pre Cost Interest (60 Months)	$246,310,804	3
Installed Cost	$2,589,310,804	
Maintenance and Plant Cost		
Cost	$2,589,310,804	
Interest Rate	5.0%	5
Term (Yrs.)	20	6
Annual Interest Pmt.	$207,772,998	
Wages	$3,860,000	1
Other	$4,620,000	
M&O	$8,480,000	1
Total	$216,252,998	

Based on Goldendale's estimates in the NOI, the project will produce about 3.5 million MWh of energy. At an estimated peak-hours average price of $50/MWh for the 8 highest NP15 daily prices, Goldendale will see revenues of about $175 million per year.

Also from the NOI, Goldendale will use about 4.4 million MWh each year to power its pumps to fill the upper reservoir. At average market prices for the 10 lowest priced NP15 daily hours Goldendale will have to pay an average of about $32/MWh and will spend about $140 million in pumping costs each year.

The relatively narrow differential between peak and off peak market prices, combined with the 20 percent efficiency penalty associated with pumping, Goldendale will net about $35 million per year at the cash flow level. However, M&O costs and debt service will lead to Goldendale losing about $181 million per year, a loss of $52/MWh of production.

Cash Flow From Operations[6]

Generation		
Capacity	1,200	4
Hrs / Day	8	4
Days /Yr.	365	4
Annual Prod (MWh)	3,504,000	4
Generation $/MWh	$50	3
Revenue from Generation	175,200,000	
Pumping		
Pumping Rate	1,200	4
Hrs / Day	10	4
Days /Yr.	365	4
Annual Pumping (MWh)	4,380,000	4
Pumping $/MWh	$32	3
Annual Pumping Cost	140,160,000	
Net Cash Flow from Operation	$35,040,000	
Profit (Loss)	**($181,212,998)**	
Cost of Production ($/MWh)	$101.72	
Profit (Loss) $/MWh	($51.72)	

6 Goldendale, PAD, pp 182; ttp://www.salestaxstates.com/sales-tax-calculator-washington;' RME; and Goldendale, PAD, pp 18.

To summarize, the minimum cost to cover debt service and O&M is about $61/MWh. The minimum market price spread for Goldendale to cover its pumping costs is 20 percent above the price Goldendale pays to fill the upper reservoir. Combined, for Goldendale to operate profitably it needs to see market prices of $61/MWh plus a price spread of about $8/MWh on top of the $32/MWh[7] estimate for the lowest cost 10 hours of pumping. Thus, with the lowest 10 hours of a typical day averaging about $32/MWh, efficiency losses will increase the value of water in the upper reservoir to about $40/MWh. Adding the $61.72/MWh necessary to cover debt service and O&M means Goldendale will need to see average prices for the 8 highest priced hours of the day of $102/MWh or higher.

[7] With efficiency losses of 20% $32/MWh pumping costs equate to $40/MWh at the generating level.

V. GENERAL DISCUSSION

Large Producer

Unlike many hydro type power producers that typically only run at full capacity during spring runoff or brief moments to match peaking demand, Goldendale can be expected to run at or near full capacity for most of its daily 8-hour operation as it attempts to maximize revenue.

When generating, Goldendale output will be one of the larger single-plant power sources in the northwest. It will be capable of out producing Bonneville Dam for the eight hours per day it generates. In terms of nameplate capacity it will be larger than McNary Dam. In terms of average production, when running, it will be on par with Chief Joseph dam and second only to Grand Coulee in the NW.

Larger Consumer

During the 10 hours per day that Goldendale will be pumping, it will be a major load center. When pumping, Goldendale will have the load equivalent of about 720,000 households, about the same as the all the residential households in Idaho![8]

Net Consumer of Electricity

Goldendale estimates that the project is 20 percent less efficient in pumping mode than it is in generating mode. The result is that to produce 3.5 million MWh of electricity Goldendale will consume about 4.4 million MWh, an annual loss to the system of about 877,000 MWh.

General Operating Characteristics

Goldendale combines some of the features of a hydro project and some of the features of a thermal project and some features unique to pump storage projects.

Like any substantial hydroelectric generating plant, Goldendale's will be a major capital investment. Servicing the interest payment on its debt will be a major challenge. In the absence of high prices in the wholesale energy market, the alternative method for absorbing overhead is

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[8] Goldendale will consume 1,200 aMW in pumping mode. Idaho has about 720,000 residential electrical customers who consume an average of about 1,200 KWh per month. (720,000 Residents X 1.2 MWh/month = 864,000 MWh. 864,000 MWh / 30 Days / 24 Hours = 1,200 MWh

to operate as many hours per year as possible. That, combined with minimal marginal operating costs, is the reason most hydro facilities operate as close to 24/7 as possible.

However, a 24/7 generating schedule will not be possible in Goldendale's case.

The requirement to spend more time filling the upper reservoir than time generating energy, plus potentially waiting out shoulder hours when the price differential is insufficient to cover pumping losses, tends to limit Goldendale's capacity utilization rate to about 33 percent. If Goldendale could generate power 16 hours per day it could double its overhead absorption and cut its pre-pumping cost of production by half. However, again, that will not be possible.

Like a thermal project, the water in the upper reservoir has value in that it costs money to pump the water the 2360 vertical feet up from lower reservoir. Like a thermal project, Goldendale cannot generate electricity profitably unless it receives at least as much per MWh as the water in the upper reservoir cost to pump it up there, plus the 20 percent efficiency penalty.

If it cost $40/MWh to fill the reservoir ($32/MWh plus a 20 percent efficiency penalty for a total of about $40 /MWh generating equivalent.), that tends to suggest that the cost minimizing operation level is when sales prices are $40/MWh or higher. That logic works well enough until about 5:00 in the afternoon when the need to absorb overhead starts to conflict with the need to cover pumping costs. In other words, just because it cost $40/MWh to fill the reservoir on one day does not mean the same water will be worth the same amount the next day. If, having paid $40/MWh to fill the reservoir there is no guarantee peak prices the next day (or the day after that, ad infinitum) will not be even lower. In that event Goldendale would be smarter, toward the end of the day, to treat the pumping costs as sunk costs and produce as much power as possible during the late afternoon / evening peak price period in an effort to absorb overhead cost, to the extent possible.

In that manner, Goldendale would cover some of its overhead and recoup at least a portion of the day's pumping cost prior to beginning the next day of operation.

Clearly, no project of this type can profitably operate in that manner on a continuing basis, but it serves to illustrate the complex nature of Goldendale's business model as it attempts to minimize losses and maximize profits.

Finally, unlike the vast majority of both thermal and hydro projects, Goldendale will never be more than about 12 hours from running out of "fuel", exhausting the water in the upper reservoir, and having to stop generating electricity.

Emergency Generating Capability

Goldendale's data table claims that the plant's approximate hours of storage @ 1,200 MW is 12 hours. The implication seems to be that Goldendale will provide 12 hours of backup for a variety of ancillary services including emergency generation in the event some other project fails.

This claim fails for a variety of reasons. First, if 1,200 MW generation requires 8,280 cfs of water flow, the 7,100 acre foot reservoir will be exhausted in a little over 10 and hours, not 12. But that misses the second and broader point, the assumption that any event triggering the need for 12 hours, or 10.5 hours, of Goldendale production will occur when the upper reservoir is at full capacity.

Barring the unlikely event that Goldendale is paid to sit patiently, 24/7, with a full upper reservoir laying in wait for a moment when its services are needed, it seems far more likely that any emergency calling for Goldendale's services will happen when the project has already been generating for some period of time. Clearly, the length of time that Goldendale can provide backup is directly proportional to the amount of water remaining in the upper reservoir.

Assuming Goldendale operates a daily pumping and generating schedule consistent with maximizing revenue from the daily price swings, any emergency calling for Goldendale's production is most likely to occur when the upper reservoir is substantially depleted. If any emergency happens after Goldendale is more than 4 hours into its daily generating cycle, or fewer than 5 hours into its daily pumping cycle, the upper reservoir will be half empty. In that manner, if emergencies happen at random times of day, the expectation is that Goldendale's ability to respond to emergencies is only about 6 hours, not 12.

Finally, if some other power plant were to go offline and need backup while Goldendale is already in generating mode as part of its daily production schedule, it is not clear that there will be a benefit to the system if Goldendale ceases putting power onto the grid under its own name to begin putting power onto the grid in the name of some other power producer. This scenario results in a zero net increase in production.

Market Price Impacts

Classical economics suggests that, at the margin, Goldendale will drive off-peak prices up and peak prices down.

Traditionally, pump-storage projects have been built in conjunction with other specific generation projects in an attempt to extend the efficiency range of the main generating plant into other parts of the day, week, month, or year.

That description does not apply to Goldendale as presented in the NOI.

Goldendale, as currently proposed, is not linked to any individual power producer, or group of power producers. It will be a parasitic operation in that it will attempt to purchase power from other existing regional suppliers during the lower cost portions of the daily price curve in an effort to resell the energy later in the day when prices are relatively higher.

Regional power producers will hope the potential for higher off-peak prices they receive when Goldendale operates its pumps will be enough to offset the potentially lower peak prices they will see later in the day when Goldendale is producing power.

On the other side of the equation, Goldendale will hope its potential to drive up off-peak prices and the potential amount it will drive down peak-prices will not narrow the price spread to the point that they cannot operate profitably.

Finally, retail consumers will hope that the net reduction in supply and the resulting potential increase in energy costs will not adversely affect their retail rates.

Minimal Price Impact

Goldendale will be one of the regions larger power producers when generating and one of the regions larger load center when pumping. As mentioned in previous sections, that tends to suggest that Goldendale will depress market prices when generating and increase wholesale prices when pumping, at least at the margin. The amount of these effects is hard to predict but will probably be fairly small.

The reason the effect will likely be small is that, while Goldendale will be a major northwest load center when pumping and a large northwest power producer when generating it will not be a large producer or load center by California standards, and it is the California wholesale markets that are the price setters.

People in the northwest tend to forget that California utilities are sized to supply the peak needs of about 40 million people while northwest utilities are sized to serve the peak needs of about 13 million people.

Goldendale may be as much as five percent of northwest capacity when generating but it will be only about one percent of California capacity. Since Goldendale will be directly connected to the west coast wholesale markets by way of the west coast power grid Goldendale will be a price taker in most cases rather than a price setter.

Self-Defeating Market Price Impact

While any market price impact resulting from Goldendale's operation will likely be small, any effect will be self-defeating for Goldendale's needs.

For example, in its analysis of Goldendale's potential profitability RME estimated peak hour and off-peak hour prices would average $50/ MWh and $32/MWh respectively. If Goldendale's operation reduces peak hour prices by $1 and raises off-peak hour prices by $1, to $49 and $33/MWh respectively, the resulting $2/MWh narrowing of the daily price spread will reduce Goldendale's annual net revenue by nearly $8 million and increase its per MWh loss by over $2/MWh to $53.97/MWh.[9]

"Quick Response" May Not Mean Lower Rates.

Goldendale lists "quick response time" as one of the project's assets. It is not clear to RME that this is a net benefit to the region.

From Goldendale's perspective, its proposed ability to supply power in response to "emergency" changes in load and or reduce the supply of power as necessary to help balance system load, is a benefit to the system.

However, quick response time can just as easily be used to respond, pumping or generating, in efforts to grasp low cost pumping opportunities or switch to generating mode to take advantage of fleeting moments of high wholesale prices. Responding to emergencies may be a benefit to the system but chasing momentary price changes can increase chaos, uncertain, and risk, and be detrimental to the system.

For instance, Goldendale has the potential to switch from consuming 1,200 MW per hour in pumping mode to producing 1,200 MW per hour in generating mode, and vice versa, in an unspecified but presumably brief period of time, perhaps as quickly as a few minutes or even quicker. To other entities on the grid, power producers, energy aggregators, and consumers, this would be seen as a 2,400 MW swing in load volume, the equivalent of a substantial western city suddenly going off line, or Grand Coulee switching arbitrarily off and on, with little or no warning!

Given Goldendale's precarious financial situation, and in the absence of regulatory or contractual operational constraints, increased wholesale market chaos appears to be the most likely result of Goldendale's operation.

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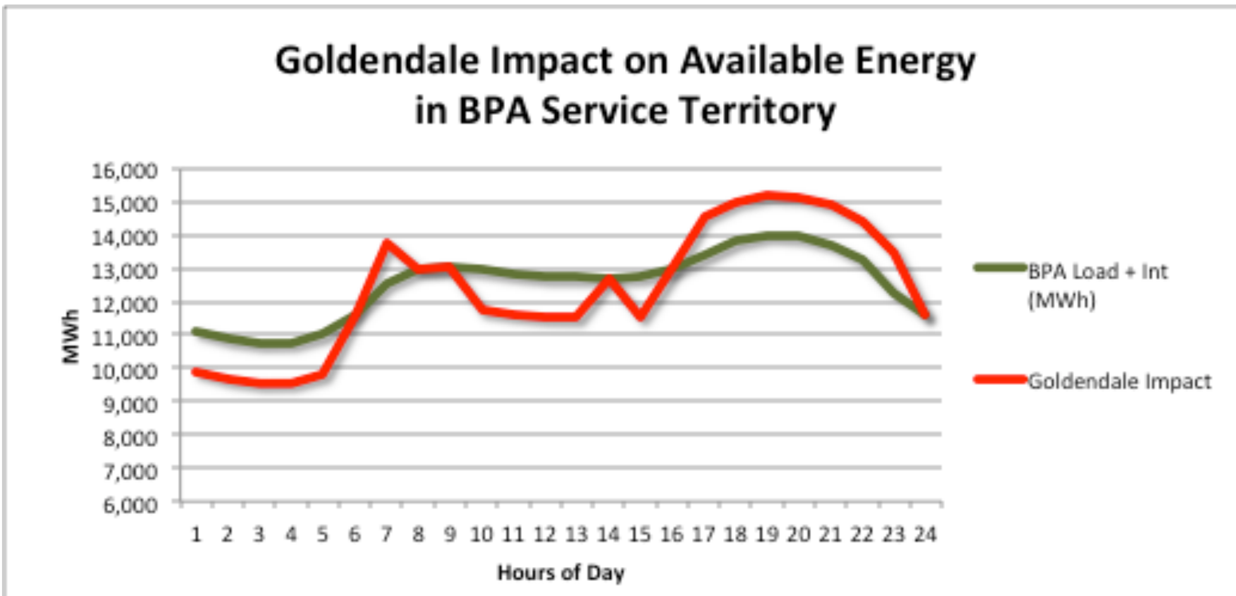
[9] RME is highly skeptical of Goldendale's potential to operate profitably. However, by choosing options and assumptions that tilt the scale in Goldendale's direction, and not including price impacts such as this, RME generally gives the benefit of the doubt to Goldendale.

Chart 4 below provides a graphical example of this discussion. If Goldendale's operation were grafted onto BPA's load curve[10] it would make BPA's available power curve substantially less "smooth" and it would make the spread, the range of power, from low point to high point, available to consumers broader by about 2,400 aMW. The power currently available to contract customers exemplified by the green line, would instead follow the red line.

Would NW producers modify their production in recognition that Goldendale is operating in that fashion? The answer is undoubtedly yes, to at least some degree. However, it is important to remember that the curve shown by the green line is the result of BPA servicing load as well as chasing the same daily price curves in search of higher revenues as Goldendale will be chasing. In other words, yes, Goldendale's operation will cause changes in the operations of other NW utilities, but it is not clear that the result will smoother or less chaotic. Absent any regulatory or contractual mandate, the opposite seems most likely.

Chart 4



As hinted at in the preceding paragraph, regulating the manner and the degree, the when and the how much if you will, to which Goldendale can enter the market could conceivably alleviate the potential for Goldendale to increase market uncertainty. That, of course, would reduce Goldendale's ability to profit from swings in market demand and prices, and make their already precarious financial picture look even worse.

[10] BPA is used here because their production numbers are roughly half of the NW, they are readily available and transparent. The inclusion of the remaining NW producers would tend to minimize this impact to some degree, but not eliminate it.

Contracting

As mentioned above, Goldendale is not directly linked to any one, or any group, of generating entities. As currently configured, it is a freelance operation.

To that end power producers in need of load shaping services may look to Goldendale for assistance. The question then becomes whether or not Goldendale can compete with other regional load shaping service providers. The evidence suggests not.

Again, Goldendale's breakeven production cost exceeds $100/MWh.

Competing with Goldendale will be most of the other NW entities with excess capacity, particularly utilities with hydro power plants that have some potential to shift their time of day production schedules. This will include BPA that touts its load shaping ability for around $40/MWh. Other hydro intensive utilities such as Idaho Power and Avista offer similar services for roughly similar prices.[11]

For companies looking for load shaping services but hoping to avoid fixed contracts there is always the option of playing the same wholesale market as Goldendale. Here, the prices may be more volatile than would be seen with a fixed contract, but with average daily prices of around $30/MWh it is hard to find justification for $100 Goldendale power.

Finally, Goldendale will have to compete with new power producers that are increasingly entering the market with rates as low as $20/MWh, including battery backup. This might seem especially galling to Goldendale since Goldendale will have trouble filling its upper reservoir for $20/MWh, let alone generating power that inexpensively.

[11] And, those prices may be a bit high. CAISO staff concludes load shaping in California only adds about $0.85/MWh to market prices. For this analysis that means Goldendale, with its $100+ / MWh cost structure trying to compete with $33/MWh market prices.

VI. APPENDIX – ALTERNATIVE DEBT STRUCTURES

Goldendale Without Amortization

In recognition that it is fairly common for utilities to not amortize debt on major projects, RME looked at the affect of Goldendale limiting its debt service to paying only the interest on the $2.6 billion startup cost. This has the benefit of reducing the debt service charge by $75 million from $219 million to about $144 million per year. Carrying the $75 million annual cost reduction through to the bottom line reduces Goldendale's losses from $192 million to $117 million per year, a loss of $33/MWh of production.

Goldendale With Bankruptcy

In the forgoing analysis RME used assumptions generally favorable to Goldendale. For example, for the market price spread, RME used the 2014 – 2018 spread of $18/MWh. The 2009 – 2018 spread is perhaps more relevant, but with a spread of only $16/MWh would have made the project look still worse. The same is true for interest rates. RME chose to use the lowest prime rate on record at the time of writing. Prime plus one or two is perhaps more accurate, especially given the speculative nature of this project, but that too would have made the project look even worse.[12]

Given that in this analysis RME made assumptions generally favorable to Goldendale and the financial results are still abysmal, RME is left to speculate on what it is that the project's sponsors see that RME does not.

Looking at the reports produced to date, and the resources at Goldendale's disposal, RME must assume the sponsors are intelligent, successful people. They must see all the same market forces and interest charges that RME sees. At the same time, the project as currently proposed appears from all angles to be destined to fail, in short order. RME is hesitant to make the following statement but feels it may be true and must be addressed: It is possible that the Goldendale Pump Storage Project is being proposed with full knowledge that it will fail. Further, bankruptcy may be an unstated but integral part of the Goldendale business plan as a means of shedding sufficient debt to survive in the current wholesale power market.

If we look at bankruptcy as an unstated but intended method of shedding the bulk of the construction cost, the project begins to make financial sense. If, in the course of a bankruptcy proceeding, the tunnels and reservoirs are declared sunk costs, and total debt is reduced to a hypothetical $75 million by salvaging the turbines and generators ($25 million apiece for three used turbines and control structures) annual debt service drops to a very reasonable $4.9 million.

[12] At the time of this writing, November 28, 2019, the prime rate is 4.75% and RME in this analysis is using a rate of Prime plus 0.25%.

Adding M&O only brings the total up to about $13.4 million. Using the same cash flow stream as in the previous examples, but with the restructured debt, Goldendale might see an annual profit of about $6.18/MWh, $21.7 million per year. Its cost of production would be about $44/MWh, comfortably lower than the average peak wholesale prices of $50/MWh.[13]

Goldendale - Without Amortization		Goldendale - With Bankruptcy	
Capital Cost		**Capital Cost**	
NOI Cost Estimate	$2,200,000,000	NOI Cost Estimate	$75,000,000
WSST @ 6.5%	$143,000,000	WSST @ 6.5%	$4,875,000
Total Estimated Direct Cost	$2,343,000,000	Total Estimated Direct Cost	$79,875,000
Pre Const Interest (60 Months)	$246,310,804	Pre Const Interest (60 Months)	$8,396,959
Installed Cost	$2,589,310,804	Installed Cost	$88,271,959
Maintenance and Plant Cost		**Maintenance and Plant Cost**	
Cost	$2,589,310,804	Cost	$88,271,959
Interest Rate	5.0%	Interest Rate	5.0%
Term (Yrs.)	1000	Term (Yrs.)	1000
Annual Interest Pmt.	$129,465,540	Annual Interest Pmt.	$4,413,598
Wages	$3,860,000	Wages	$3,860,000
Other	$4,620,000	Other	$4,620,000
M&O	$8,480,000	M&O	$8,480,000
Total	$137,945,540	Total	$12,893,598

[13] One simple waty to eleimiante the possibliity of bankruptcy as an unstated but integral part of Goldendale's business plan is to include a clause in any regulatory approval of the project requiring Goldendale to set aside funding to remove the turbines and destroy the tunnel in the event the project fails.

Cash Flow From Operations

Generation	
Capacity	1,200
Hrs. / Day	8
Days /Yr.	365
Annual Prod (MWh)	3,504,000
Generation $/MWh	$50
Revenue from Generation	175,200,000
Pumping	
Pumping Rate	1,200
Hrs. / Day	10
Days /Yr.	365
Annual Pumping (MWh)	4,380,000
Pumping $/MWh	$32
Annual Pumping Cost	140,160,000
Net Cash Flow from Operation	$35,040,000
Profit (Loss)	**($102,905,540)**
Cost of Production ($/MWh)	$79.37
Profit (Loss) $/MWh	($29.37)

Cash Flow From Operations

Generation	
Capacity	1,200
Hrs. / Day	8
Days /Yr.	365
Annual Prod (MWh)	3,504,000
Generation $/MWh	$50
Revenue from Generation	175,200,000
Pumping	
Pumping Rate	1,200
Hrs. / Day	10
Days /Yr.	365
Annual Pumping (MWh)	4,380,000
Pumping $/Who	$32
Annual Pumping Cost	140,160,000
Net Cash Flow from Operation	$35,040,000
Profit (Loss)	**$22,146,402**
Cost of Production ($/MWh)	$43.68
Profit (Loss) $/MWh	**$6.32**