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2014
2nd REVIEW OF THE ECONOMICS OF RESTORING HYDROPOWER AT ENLOE DAM ON THE SIMILKAMEEN RIVER

ANALYSIS OF THE PUBLIC UTILITY DISTRICT NO. 1 OF OKANOGAN COUNTY'S FINAL LICENSE APPLICATION FOR FEDERAL ENERGY REGULATORY COMMISSION PROJECT NO. 12569

Prepared for

Hydropower Reform Coalition

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EXECUTIVE SUMMARY

On August 22, 2008, the Public Utility District No. 1 of Okanogan County (OPUD or Applicant) filed its Final License Application for the Enloe Project with the Federal Energy Regulatory Commission (FERC). In its application (page IS-6), OPUD stated "It is considered economically feasible to redevelop the project with new generating facilities…"

In 2011 the Hydropower Reform Coalition (Coalition) contracted with Rocky Mountain Econometrics (RME) to review OPUD's application to determine the extent to which changes in the economy and provision for minimum instream flows over the falls would impact OPUD's application. The 2011 Review of the Economics of Restoring Enloe Dam on the Similkameen River[1] demonstrated that OPUD's analysis is flawed and that the project is not economically feasible.

On July 9, 2013 FERC issued its Order approving a new license, and today, notwithstanding evidence of project monetary losses and other uncertainties, the OPUD continues to pursue repowering Enloe Dam.

At the request of the Coalition, RME revisited its 2011 study of the Enloe Project to determine whether changes have occurred that would warrant a change in earlier estimates of Enloe's profitability. The 2014 study concluded:

- In 2008 the Applicant estimated it would cost about $31 million to complete the Enloe Dam Project. By 2011 RME estimated that inflation would drive Enloe's cost to about $40 million and above in subsequent years.

- While open market prices are firmer than in 2011, the long-term trend, adjusted for inflation, is still downward. RME's 2014 conclusion is the same as in 2011 that current prices continue to be only about two-thirds as high as OPUD anticipated in 2008. When compared to the prices at which OPUD can acquire energy on the open market, Enloe dam will, depending on the amount of water dedicated to minimum instream flows over the falls (see below), lose between $1.1 million and $1.5 million per year, a loss of $25 to $41 on every MWh of electricity it produces.

- With revenue tied to the NP15[2] average alternative cost of power at $47.09, OPUD will see operating income of only $2.1 million each year. With operating costs totaling $3,193,696 it will cost OPUD $1.1 million more each year to

1 www.rmecon.com/Final%202%20Enloe%20Economics%20Study%201%2024%2012.pdf

2 NP15 Day Ahead Market (DAM), the Northern California trading hub, is one of the world's largest trading hubs. It is the western market with perhaps the longest record of price trades. The prices of trades are recorded on a continuous basis as short as 10 minutes and, of critical importance, the prices are published openly and publicly for scrutiny by one and all.

operate the Enloe Project than it would cost to purchase the power on the open market.

In addition to revisiting 2011 economic projections, the Coalition asked RME to address some of the remaining uncertainties that may affect the economic viability of this project. Specifically, how required and potentially increased minimum flows through the bypass reach would further impact OPUD's 2008 projections.

In 2013, Coalition members appealed the Washington State Department of Ecology's 401 Water Quality Certification required under the Clean Water Act. Ecology's original 401 Certification required 10/30 cubic feet per second (cfs) minimum instream flow year-round over Similkameen Falls, which is within the bypass reach of the Enloe Project. The Pollution Control Hearings Board agreed with Coalition members that there was no evidence supporting Ecology's conclusion that the 10/30 cfs instream flow requirement would comply with state water quality standards for aesthetics and recreation. The Board therefore required Ecology to conduct a minimum flow study within three years after the project is built, and determine a suitable minimum flow at that time. To date, all economic studies demonstrate that Enloe will lose money even at this 10/30 cfs flow. Any bypass flow higher than 10/30 cfs will result in additional economic loss. RME evaluated the economic impact of having instream flows of 100 cfs and 300 cfs,[3] and estimates that each additional 100 cfs dedicated to minimum instream flows through the bypass reach will result in additional economic losses of about $100,000 per year. At the 100 cfs level, losses for each year will total $1.2 million. At the 300 cfs level, losses each year will approach $1.5 million.

Finally, the Coalition requested that RME address OPUD statements regarding how (1) Enloe generation could result in premium "green" pricing; (2) how Enloe could receive higher pricing as a backstop to wind or solar projects, and; (3) that OPUD can run Enloe at a long term (40+ year) loss and then begin to see a profit once construction debt has been retired. On these questions, RME concludes:

- In the unlikely event Enloe qualified as green power, the premium would not be enough to cover Enloe's losses.

- As a run-of-river project, Enloe's generation is not dispatchable (able to ramp generation up and down), and thus cannot effectively back up intermittent wind and solar projects.

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[3] The 100 and 300 cfs flow alternatives were arbitrarily selected by RME for illustrative purposes and are actually conservative estimates of the instream flows likely to be found compliant with water quality standards after the instream flow study is completed. As the Coalition's experts concluded, "[a] flow evaluation curve based on photos of Similkameen Falls (produced in this report) shows that marginal aesthetic flows start at about 350 cfs and become totally acceptable by 450 cfs; for the Dam Falls, marginal aesthetic flows start about 150 cfs and become totally acceptable by 350 cfs." Shelby & Whitaker, "Aesthetics and Recreation Issues at the Enloe Hydroelectric Project: Expert Witness Report" (Feb. 4, 2013) at 30.

- While the original loan for the project will be paid off at the end of year 40, accumulated losses plus interest will have grown to nearly $170 million, more than four times the original construction cost. At that time, Enloe will be losing about $10 million per year and the net present value will never generate a profit.

These losses to OPUD will not, strictly speaking, drive OPUD bankrupt. However, they are literal losses to OPUD Ratepayers. To avoid these losses, OPUD will need to pass this debt on to its ratepayers in the form of higher rates. Based on OPUD's approximately 20,000 ratepayers and a minimum instream flow of 300 cfs, RME's estimate is that the Enloe Project will result in an increase of $50 for each ratepayer, each year, in perpetuity.

These numbers represent real loses to ratepayers who have a reasonable expectation for OPUD to provide power in a least cost fashion and have extremely limited options for avoiding or mitigating the mistakes of the OPUD. Based on the average monthly residential electrical cost for electricity in Washington State, this represents an increase of between 5% and 6% for each ratepayer.[4]

INTRODUCTION

Toward the end of 2008 OPUD filed an application with FERC to renovate Enloe dam and to generate electricity.[5]

The timing of OPUD's analysis and application were coincident with the run up to the final peak of the economic bubble immediately preceding the biggest economic recession since the Great Depression.

Similar to many financial analyses performed prior to the crash, OPUD erroneously concluded that the project would operate profitably over the course of its life, producing $440,021 in profits to the OPUD, at a rate of $9.79 of profit for every MWh of energy generated at Enloe.

In 2011 the Hydropower Reform Coalition contracted with RME to review OPUD's application to determine the extent to which changes in the economy and provision for aesthetic flows over the falls would impact OPUD's application.

Three years into the recession, with open market wholesale energy prices having declined by roughly 70 percent, rather than running at a profit, RME estimated that OPUD would lose $31.16 on every MWh of energy produced at Enloe. RME estimated that if OPUD

[4] The average monthly residential electric billing for Washington State, in 2012, was $78.43 as reported by http://calc.myenergy.com/ and $88.46 according to recently related data from the US Energy Information Administration (EIA) http://www.eia.gov/electricity/sales_revenue_price/

[5] FEDERAL ENERGY REGULATORY COMMISSION, ENLOE HYDROELECTRIC PROJECT, (FERC PROJECT NO. 12569), FINAL LICENSE APPLICATION, August 2008.

pursued the Enloe Project it would lose more than $1.4 million each year the project operated.

In 2013, FERC approved OPUD's application and issued a license to generate electricity at Enloe Dam.[6] In the process FERC made minor changes to OPUD's operating assumptions. They included a provision for very minor minimum stream flows over the falls (10/30 cfs), thus reducing the annual MWh production by a modest amount. More significantly, rather than looking at wholesale open market energy as the prime alternative energy price metric, as did OPUD and RME, FERC interjected the cost of operating a gas fired thermal plant into the equation. After inflating OPUD's cost estimates into $2013 values, and using the gas fired thermal plant as the avoided cost energy price, FERC estimated that Enloe would operate at a profit but the per MWh margin was down from OPUD's projection of $9.79 to less than $2.00/MWh.

FERC approved OPUD's application but OPUD has not commenced construction as of the date of this report. Final minimum aesthetic flows over the falls have not been established for the project, and will not be set until the OPUD completes a legally mandated aesthetic/recreation flow study. Litigation continues regarding the OPUD's application for additional water rights to run the project. In addition, on October 15, 2014 OPUD issued a request for proposal (RFP) looking for someone to purchase, lease, design, bid, build, operate and/or maintain the Enloe Hydroelectric Project. With these factors in mind, the Coalition contracted with RME to take a second look at the economics of reconstructing and re-commissioning Enloe Dam to determine the degree to which earlier financial projections still apply. This study briefly reviews OPUD's, RME's, and FERC's preceding economic analyses and then describes how little the economy has recovered since 2007 to restore the economic viability of the Enloe Hydroelectric Project.

[6] 144 FERC, 62,018, Project No. 12569-001, ORDER ISSUING NEW LICENSE, (July 9, 2013)

OPUD'S APPLICATION TO FERC (2008)

Table 1, Comparison of Enloe, FERC, and RME Analyses 4

Column	1	2	3	4	5	6	7
Title	Enloe Application	RME	FERC (146)	FERC (147)	RME 10-30	RME 100	RME 300
Year ($Yr.)	2008 ($2007)	2011 ($2011)	2013 ($2013)	2013 ($2013)	2014 ($2014)	2014 ($2014)	2014 ($2014)
Levelized Ann. Operating Cost	$2,611,883	$3,356,716	$3,207,950	$3,220,550	$3,193,696	$3,193,696	$3,193,696
Est. Avg. Ann. MWh	44,963	44,963	44,409	44,409	44,409	41,820	36,068
Operating Cost/MWh	$58.09	$74.66	$72.24	$72.52	$71.92	$76.37	$88.55
Market Price for Power	$66.62	$43.50	$74.22	$74.22	$47.09	$47.09	$47.09
Revenue	$3,051,904	$1,955,891	$3,296,036	$3,296,036	$2,091,007	$1,969,122	$1,698,266
Profit (Loss)	$440,021	$(1,400,825)	$88,086	$75,486	$(1,102,690)	$(1,224,575)	$(1,495,430)
Profit (Loss) per MWh	$9.79	$(31.16)	$1.98	$1.70	$(24.83)	$(29.28)	$(41.46)
Profit (Loss) per Customer per Yr.[7]	$22.00	$(70.04)	$4.40	$3.77	$(55.13)	$(61.23)	$(74.77)

Column 1 in Table 1 above presents the major economic decision factors as they appeared in OPUD's 2008 application to FERC to renovate and re-commission Enloe Dam. At that time OPUD estimated that it would cost about $30 million to bring the project online. Based on that and other assumptions, in 2008 OPUD concluded that Enloe Dam could generate profits of about $9.79 for each MWh the project produced for a total profit in excess of $440,000 for OPUD per year.

[7] Based on a base of approximately 20,000 ratepayers.

The biggest issue with OPUD's analysis is not the numbers they generated, or their general conclusions. Rather, it is the economic time during which the analysis was performed. Generally, OPUD did everything about as well as could be expected at that moment in time. Their construction costs and operating costs seemed reasonable. Choosing to use MID-C pricing as the best metric for the cost of alternative energy was, and still is, the appropriate choice.

The main problem with OPUD's pre-license analysis is that OPUD performed their analysis before the biggest economic crash in the last 80 years. Economists the world over have recognized the crash and the need to review and recalculate pre-crash data. OPUD, however, has not done that.

RME ANALYSIS OF ENLOE DAM, (2011)

Column 2 in Table 1, above, shows RME's 2011 review of Enloe.

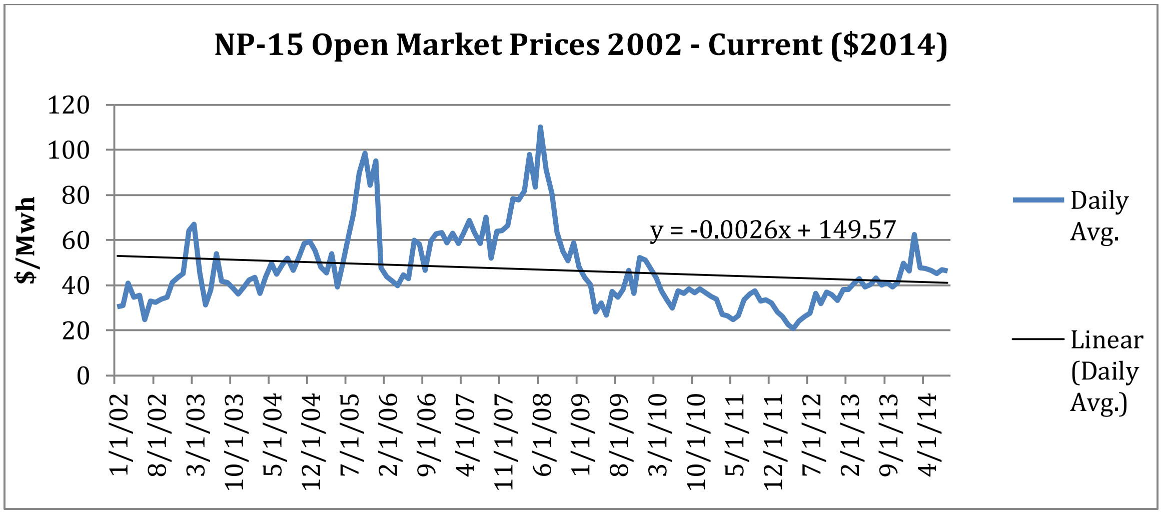
In 2011 the world was deep in recession and it was clear that the financial world, and the northwest energy climate, had changed substantially.

Construction costs for large projects such as Enloe had continued to increase. The increase may not have been as fast as prior to 2008, but every indication is that costs had continued to climb. In 2011 RME estimated that construction costs would total about $40 million.

Construction costs had continued upward but the opposite was true of open market wholesale energy prices. A combination of static, or even declining, demand pared with significant new amounts of wind generation and other resources in the NW sent prices tumbling. Please refer to Chart 1, below.

In 2008, NP15 day-ahead prices were above 100/MWh for the month of June, and averaged 70.43/MWh for the entire year. By 2011 prices at NP15 had dropped to 30/MWh and it appeared they would continue even lower.

Chart 1, History of Day Ahead Open Market Energy Prices at NP15.



To estimate Enloe's profitability, RME used the average of the previous ten years, in constant (2011) dollars, $43.55 per MWh, at NP15.[8]

RME's bottom line in 2011 was that if OPUD went forward with the Enloe rebuild as proposed in the FERC license application, they would lose about $31 on every MWh Enloe produced for total losses of about $1.4 million per year for the life of the project. Losses of that magnitude would have amounted to $70.04 per year for each of OPUD's 20,000 customers.

FERC ECONOMIC ANALYSIS of ENLOE, (2013)

Columns 3 and 4 in Table 1, above, show FERC's economic analysis of the Enloe Project as presented in FERC's order issuing a new license to the OPUD dated July 9, 2013.[9]

In their economic analysis FERC, with a couple of exceptions, accepted OPUD's economic predictions and assumptions. FERC used the Consumer Price Index (CPI) to inflate OPUD's cost numbers, bringing them up to 2013 levels. They also made provision for a minimal amount of water, 10/30 cfs, to be required for minimum instream flows over the falls thus reducing the annual MWh production by a minor amount. FERC relied upon the 10/30 cfs instream flow requirement in spite of the fact that this flow is not final nor legally compliant. In 2013, the Pollution Control Hearings Board (PCHB) ruled that there was no evidence in the record to support OPUD's and Ecology's conclusion that the 10/30 cfs instream flow requirement would comply with state water quality standards. Therefore the PCHB ordered Ecology to conduct an

[8] Appendix 4, RME 2011, pp. 14.

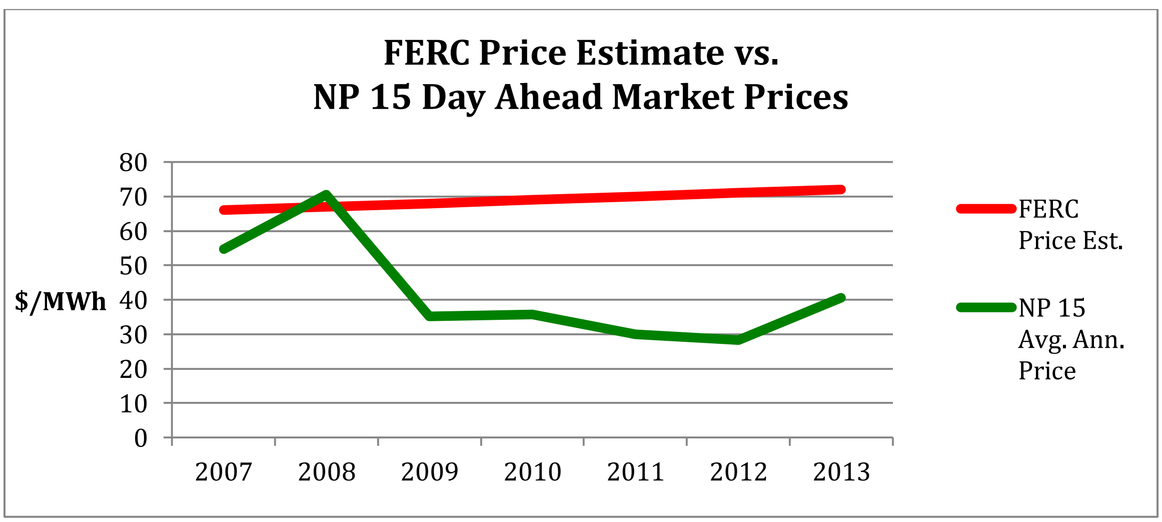
[9] 144 FERC, 62,018, Project No. 12569-001, ORDER ISSUING NEW LICENSE, (July 9, 2013)

aesthetic/recreation flow study in order to identify the appropriate minimum instream flow requirement for the Enloe Project. That study has not been completed and will not be completed until up to three years after project operation. Therefore, it is presently unknown how much instream flow will be required to pass through the bypass reach and thus taken out of the power-generating equation. It is highly unlikely that the 10/30 cfs instream flow requirement will ultimately be found to be compliant with state water quality standards.[10]

More significantly, rather than looking at wholesale open market energy as the prime alternative energy price metric, as did OPUD and RME, FERC instead compared Enloe generation to the cost of operating a gas fired thermal plant. Where OPUD had used $66.62/MWh as the opportunity cost of power in 2007, FERC used $74.22, the cost of running a gas turbine, as the avoided cost rate in 2013.

Chart 2, below illustrates how drastic this change in the FERC price estimate is relative to NP15. In 2007, gas fired thermal plants were reasonably close to wholesale prices at MID-C and NP15. However, since 2008 the operating cost of gas fired thermal plants has continued to increase while NP15 prices dropped by roughly 50 percent before rebounding slightly in 2013 to about $40/MWh. By using the cost of operating a thermal plant, FERC gives OPUD a price bonus of roughly 65 percent.

Chart 1, FERC Alternative Energy Pricing vs. NP15 Open Market Prices



[10] "The proposed 10/30 cfs flow requirement does not protect the aesthetics of Dam Falls or Similkameen Falls. Thirty cfs is a 94% reduction of the 500 cfs natural low flow typically found during dry months of the year, and doesn't come close to filling the bottom of the channel," an important characteristic with respect to aesthetic flows. Shelby & Whittaker, "Aesthetics and Recreation Issues as the Enloe Hydroelectric Project: Expert Witness Report" (Feb. 4, 2013) at 30.

Even though open market prices are substantially lower than thermal plant operating costs, and the wholesale open market is a viable alternative source for volumes as low as might be supplied by Enloe, FERC used a thermal plant as the avoided cost energy price for the Enloe license. On that basis FERC estimated, in $2013, that Enloe would operate at a profit but the per MWh margin was down from OPUD's prediction of $9.79 to less than $2.00. If these profits were spread evenly across OPUD's 20,000 ratepayers, the typical customer would receive a bonus of $3.77 to $4.40 each year.[11]

RME ANALYSIS OF ENLOE DAM (2014)

Columns 5 through 7 in Table 1, above, show RME's latest estimate of the financial outlook for the Enloe Project in relation to all previous analyses. Column 5 presents the case if 10/30 cfs is set as the minimum instream flow requirement. Column 6 shows the effect of increasing the minimum instream flow requirement to 100 cfs and column 7 shows the impact of a minimum instream flow of 300 cfs. All instream flow options depend upon the results of the legally-mandated instream flow study. For tables detailing aesthetic flow impact on energy production refer to Appendix 1.

In each of these three columns RME used the same weighted average of Producer Price Indexes (PPI) to bring OPUD's original construction cost and operating cost estimates up to current dollar values ($2014). Because the cost of turbines represents about 30 percent of the total construction cost, RME used the "Turbine and turbine generator set units mfg." series (PCU333611333611) for 30 percent of the inflator, and the all industry PPI for the remaining 70 percent. Interestingly, the RME total generation cost number of $3,193,696 is within about $14,000 of FERC's lower 2013 estimate. The difference reflects, in part, the difference between using CPI in FERC's case, and PPI in RME's version.

In each of these three columns RME also used the same open market wholesale energy price of $47.09/MWh.

Brief Discussion of Wholesale Prices

Picking a representative open market price can be based on a range of variables. In 2011 RME arrived at an avoided cost rate of $43.50 ($2008) by averaging the previous ten-year's data at NP15.12 This process had the advantage of being consistent with OPUD's methodology, bringing the number up to date in the post-bubble world, and also being somewhat generous to OPUD. The average NP15 price for 2011, in 2007 dollars was only $27.156. Using the ten-year average, plus adding in a $3/MWh differential between MID-C and NP15 gives OPUD a roughly $19/MWh benefit of the doubt on the revenue side over the then-current NP15 price.

[11] RME analysis of Enloe Dam, (2014)
[12] RME, 2011, pp. 14.

The long-term price trend at NP15 continues to be negative even though the price trend since 2009 is slightly positive. Table 5 below provides a list of price measures at NP15, all adjusted for inflation to bring them up to $2014.

Table 2, NP15 Price Measures[13]

Average since January 2002	$47.0852
Average since January 2009	$37.3784
Average for Last 12 Months	$45.9790
Average for Most Recent Month	$46.3067
Oct 2014 Based on Trend for 2009 - 2014	$40.6441

The average for the most recent 12 months, at $45.98, is $2.5/MWh higher than the number RME used in 2011. The average for the most recent month, at $46.31/MWh is a bit higher still, $2.80/MWh higher than RME's 2011 number.

There would be a justified basis for using either of those numbers. However, for the sake of consistency with RME's and OPUD's earlier efforts it makes more sense to use the same methodology RME used in 2011. By calculating the average NP15 price since 2002 we arrive at a value of $47.09 ($2014). Using this number has the advantage of being consistent with OPUD's logic in its application and, with RME's earlier price estimation and, recognizing that the long term trend is still downward, provides a small bonus to OPUD in addition to the $3/MWh NP15 to MID-C differential.

This brings us back to Column 5 in Table 1. Having updated the levelized operating cost at $3.194 million per year, and duplicated FERC's estimated average annual MWh generation of 44,409, the operating cost per MWh comes in at $71.92. This is within $0.32 per MWh of FERC's lower number. However, with revenue tied to the NP15 average alternative cost of power at $47.09, OPUD will see operating income of only $2.1 million each year. With operating costs totaling $3,193,696 it will cost OPUD $1.1 million more each year to operate the Enloe Project than it would cost to source the power on the open market. OPUD will lose $24.83 on every MWh they produce at Enloe. This assumes minimum instream flows of 10/30 cfs, which are unlikely.

Columns 6 and 7 present the economic impact of two alternative levels of minimum aesthetic flows over the falls. Column 6 shows the impact if aesthetic flows are set at 100 cfs. Column 7 shows the impact of setting aesthetic flows at 300 cfs.

In each case, operating costs are held constant at $3.2 million per year and the market price for power is held constant at $47.09 per MWh. The only difference is the reduced amount of water available to turn the turbines for electricity generation.

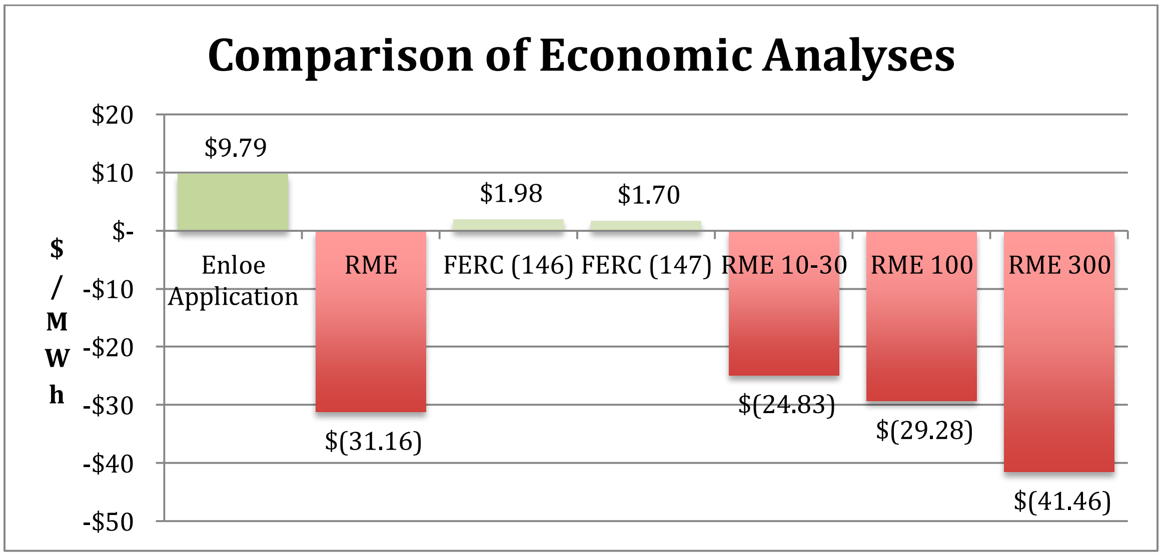
[13] Source RME, Market Prices and Trends, Tab 2002 - 2013

In the 100 cfs minimum instream flow scenario (column 6), Enloe produces 41,820 MWh. This drives operating costs per MWh up to $76.37. Revenue declines to $1.97 million and net losses increase to $1.2 million per year. If minimum instream flows are set at 100 cfs Enloe will lose $29.28 on every MWh it produces.

Column 7 shows the impact of minimum instream flows of 300 cfs. Energy production drops even further to 36,068 MWh, thus sending operating cost per MWh up to $88.55. The reduction in energy production reduces revenues to $1.7 million per year. At that level, Enloe will be losing $1.5 million per year, or $41.46 on each MWh it produces, for the life of the project. Any additional increase in minimum flows above and beyond 300 cfs, which is a probable scenario, would additionally reduce revenues of the Enloe Project.

For a graphic representation of the various alternatives, please refer to Chart 3 below.

Chart 2, Comparison of Enloe Analyses Conclusions



COULD OPUD SELL ENLOE PRODUCTION AS "GREEN" POWER AND RECEIVE PREMIUM PRICES?

A. OPUD could certainly try to sell Enloe power as green power but there is doubt as to whether they would succeed. Green-e, the people that certify the legitimacy of green energy claims, considers hydropower as eligible to supply Green-e Energy certification only if the project meets "all applicable eligibility rules," and under the following conditions:

> 4) Hydropower from new generation capacity on a non-impoundment or new generation capacity on an existing impoundment that meets one or more of the following conditions:

a) The hydropower facility is certified by the Low Impact Hydropower Institute (LIHI);
b) For Canadian hydropower facilities only, the facility is EcoLogo certified; or
c) The hydropower facility consists of a turbine in a pipeline or a turbine in an irrigation canal.

Enloe is not LIHI certified, and is not new generation on a pipeline or irrigation canal. Further, Green-e criteria specifically exclude projects that, "increase water storage capacity or the head of an existing water reservoir(s)." As documented in the final license, the Enloe Project proposes to both increase storage and increase capacity.[14]

Like Green-e, hydropower generation in Washington State is considered renewable energy under the State's Renewable Portfolio Standard (Initiative 937) "where the new generation does not result in new water diversions or impoundments."[15] Again, Enloe does both.

In 2011, the Washington Utilities and Transportation Committee's I-937 Technical Working Group (TWG) issued an <u>Analytic Guidance for Tacoma Power's Lilliwaup Falls Hydropower Project</u>. Similar to Enloe, this project was constructed in the 1940's and extensively rebuilt in the 1980's. The workgroup addressed the question of whether the power generation after repair and restart qualifies as incremental hydropower. The TWG found that Lilliwaup Falls is an existing hydroelectric project with a history of power generation, and that the "TWG does not consider repairing or restarting the plant an efficiency improvement." Any incremental improvement should be calculated compared to the baseline production of the plant when it was in operation. This Lilliwaup finding is also applicable to Enloe, which will also generate after repair and restart.

B. In the unlikely event Enloe would qualify as green power, the next question is whether the premium would be sufficient to cover Enloe's losses. Referring back to Table 1, Columns 5 - 7, Enloe, as currently configured, would lose between $24.8 and $41.46 per MWh of production, depending on the required level of mandated instream flow. For green power premiums to move Enloe into the realm of profitability, green power premiums would have to be high enough to offset those losses. Current evidence of green power premiums indicates that this is not possible.

Table 6, below, presents a sampling of green power premiums in western states.

The current minimum premium for hydroelectric green power is $4/MWh in New Mexico. The average premium, $15.09/MWh, the Median premium, $12/MWh, and the

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14 "The proposed project includes restoring the functionality of the flashboards on the crest of the existing spillway by retrofitting crest gates. These gates would be 5 feet high, and would increase the water level upstream of the dam and the hydraulic head [capacity] available for power generation." Final License Application, Volume 1, Exhibit A, Project Description, Dam and Spillway (Page 5). August 2008.

15 WAC 194-37-130. http://app.leg.wa.gov/wac/default.aspx?cite=194-37-130

most common premium, \$8.00/MWh, are all too low to move Enloe into profitable territory. Only the maximum premium of \$35 per MWh, of which there is only one listed example, is enough to move Enloe into the realm of profitability and then only for the two lower minimum instream flow scenarios. If instream flows are set at 300 cfs, the maximum green power premium would still be insufficient to make Enloe profitable.

Keep in mind that these are retail premiums. At the producer level, transmission, load shaping, dispatch, and other costs need to be subtracted. If those costs approach 10 percent of the total, the \$35/MWh number becomes \$31.5/MWh. At \$31.5/MWh Enloe would still be profitable at the 100 cfs aesthetic flow level, but the margin would be a scant \$1.62/MWh.

Table 3, Western States Green Power Premiums[16]

State	Green Power (Hydro) Premium ($/MWh)
AZ	$8.00
CA	$10.00
CO	$23.30
CO	$8.00
MT	$8.00
NM	$4.00
NM	$25.00
OR	$12.00
UT	$29.50
UT	$8.00
WA	$35.00
WA	$20.00
WA	$12.50
WA	$15.00
WY	$8.00

Statistical Measure	Green Power (Hydro) Premium ($/MWh)
Average	$15.09
Median	$12.00
Mode	$8.00
Maximum	$35.00
Minimum	$4.00

COULD ENLOE PROVIDE BACKUP RESERVE CAPACITY FOR WIND OR SOLAR PROJECTS AND THUS OBTAIN HIGHER PRICES?

The concise answer is that Enloe is not likely to serve as backup reserve capacity for wind and solar projects. For hydroelectric power to be a good symbiotic fit with wind, the project must be able to increase production, often for days at a time to cover for wind turbines when winds are calm, and then throttle back production to recharge the reservoir when the wind is blowing. Similarly for solar, Enloe would have to ramp up production at night and when it is cloudy, again for days at a time, and then throttle back production to refill the reservoir during sunny periods. As a run-of-river project, Enloe cannot do this. In addition, Enloe's ability to operate in such a manner will be constrained by any instream flow requirements, which are currently unknown.

At 9 MW, Enloe would be smaller than many, perhaps most, state of the art wind farms.

And, as a small project with a small reservoir, the length of time Enloe can throttle the project up or down is extremely limited. According to OPUD, "The mean hydraulic residence time is estimated to be about 2.4 hours for the mean annual flow. It reduces to just 45 minutes at the mean annual peak flow of 16,100 cfs, and increases to 7.3 hours at

[16] http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml? Page=1

the mean September flow of 596 cfs. Residence time would exceed 20 hours at flows less than 200 cfs."[17]

In other words, in all but the driest months, even if OPUD wanted to operate the project in a dispatchable fashion, they can usually only do so for, at most, a few hours at a time.

The bigger point is that Enloe, as currently proposed and licensed, is not dispatchable. In the application OPUD proposed to operate the project in a run-of-river fashion.[18] In FERC's license they require OPUD to provide detailed descriptions of how the licensee will document compliance with run-of-river operation.[19]

Since the project will not be dispatchable, it cannot provide backup for intermittent wind and solar projects and thus it cannot demand premium pricing in that context.

WOULD THE PROFITS ASSOCIATED WITH OPERATING ENLOE AFTER THE CONSTRUCTION DEBT IS RETIRED BE SUFFICIENT TO OFFSET EARLIER LOSSES?

Often, developers believe that, if they can hang on until the construction debt is retired, decades into the future, the project will then be much cheaper to operate and will then be profitable.

Economists phrase the concept a little differently. The issue, in economic terms, is whether or not the developer can ever get "in front" of the interest on the original debt.

Unfortunately, if a project doesn't have a clear path toward profitability in the near future, typically less than 10 years, or if the annual losses are significant, it will probably never be profitable. The reason is that the debt from each succeeding year gets stacked on top of the debt from all the preceding years, in addition to all the interest on all the debt from all the preceding years. As time marches on, the debt increases and the accumulating debt often becomes bigger than the original investment.

The example presented in Table 7 below illustrates the problem. This example is based on column 5 in Table 1 above. Once again the project produces 44,409 MWh of energy. In the first year of operation the avoided cost price of power is $47.0852/MWh, and revenues are $2.1 million per year. The Capital cost of the plant is $38 million that, at 4.5% interest for 40 years, requires an annual payment of $2.1 million. Insurance, taxes, M&O, etc. bring total year one operating costs to $3.2 million for a net loss in the first year of operation of $1.1 million.

In following years all costs and all prices, with the exception of the fixed construction

[17] Public Utility District No. 1 of Okanogan County, Final License Application, pp. A-13
[18] Public Utility District No. 1 of Okanogan County, Final License Application, pp. B-18
[19] 144 FERC, 62,018, Project No. 12569-001, ORDER ISSUING NEW LICENSE, (July 9, 2013), pp. 53

loan and the loan for environmental features, are inflated at 3% per year. Those two items remain fixed for the life of the loans.

The question becomes one of how to handle the annual losses. Strictly speaking, OPUD can raise rates and cover the cost. However, that does not alter the fact that their ratepayers are paying more than would be the case if OPUD acquired the same amount of power at NP15. For the purpose of this example RME rolls each year's losses into the equivalent of a running line of credit with a 20-year amortization schedule at 5.5% interest.

In the first few years of the project, the problem does not appear to be too severe. Losses in year one are $1.1million. In years two through five the annual losses continue to get a little bigger but they still seem manageable. Total debt in the line of credit account in year 5 is has grown to $4.8 million.

The problem starts to become more evident out around year 15. At that point, even though the annual losses are only up to the $2 million range, the year after year accumulation, plus interest, is starting to pile up. In year 15 the line of credit is up to $21.9 million, roughly half of the total original cost of the project.

By year 30 it is clear things are not going well. In year 30 the annual accumulation of debt and interest on the debt has driven debt in the line of credit account to $75 million, nearly double the cost of the project. At that point the cost of servicing the original debt, plus the cost of servicing the line of credit, drives annual losses up to $5.5 million, roughly 5 times the annual losses in year one.

Fast forward to year 42 of the project. The original loan for the project will be paid off at that point. That is good news. That means the annual debt service associated with Enloe's construction, $2.1 million per year, would cease. The bad news is the debt in the line of credit account will have grown to a whopping $170 million, more than 4 times the original construction cost. At that point the project will be losing about $10 million per year and the amount will keep going up in perpetuity.

Again, these are not literal loses to OPUD, the company. They will not, strictly speaking, drive OPUD bankrupt. However, they are literal losses to OPUD Ratepayers. These numbers represent real loses to ratepayers who have a reasonable expectation for OPUD to provide power in a least cost fashion and have extremely limited options for avoiding or mitigating the mistakes of the OPUD.

Table 4, Debt Accumulation Demonstration ($1,000s)

Year		1	2	3	4	5	15	30	40	41	42	43
Annual Generation (MWh)		44,409	44,409	44,409	44,409	44,409	44,409	44,409	44,409	44,409	44,409	44,409
Open Market Price		$0.05	$0.05	$0.05	$0.05	$0.05	$0.07	$0.11	$0.15	$0.15	$0.16	$0.16
Revenue		$2,091	$2,154	$2,218	$2,285	$2,353	$3,163	$4,928	$6,622	$6,821	$7,026	$7,236
Plant Investment												
Plant Investment Debt		$38,033	$37,678	$37,307	$36,918	$36,513	$31,306	$17,628	$1,978			
Annual Cost												
I. Construction Debt Service												
a. Interest on Capital	4.50%	$1,711	$1,696	$1,679	$1,661	$1,643	$1,409	$793	$89	$0		
b. Capital recovery cost (40yr, 4.5%)	0.93%	$355	$371	$388	$406	$424	$658	$1,274	$1,978	$2,067		
Total Plant Debt Service		$2,067	$2,067	$2,067	$2,067	$2,067	$2,067	$2,067	$2,067	$2,067		
Line of Credit - Operating Debt												
Total Operating Debt			1,104	2,262	3,479	4,757	21,923	74,645	148,754	159,131	170,210	179,978
a. Interest on Capital	4.50%		50	102	157	214	987	3,359	6,694	7,161	7,659	8,099
b. Capital recovery cost (20yr, 5.5%)			35	72	111	152	699	2,379	4,742	5,072	5,426	5,737
c. Total Operating Debt Service			85	174	267	366	1,685	5,738	11,436	12,233	13,085	13,836
II. Insurance	0.20%	$76	$78	$81	$83	$86	$115	$179	$241	$248	$256	$263
III. Taxes - Privilege Tax (% of first 4 mills/kWh)	5.35%	$10	$10	$10	$11	$11	$15	$23	$30	$31	$32	$33
IV. Operation and Maintenance (1.9% of Invest Cost)		$737	$759	$782	$806	$830	$1,115	$1,737	$2,335	$2,405	$2,477	$2,551
V. Environmental Measures (40yr, 4.5%)		$35	$35	$35	$35	$35	$35	$35	$35	$35	$35	$35
VI. Administrative and General/Contingency	35.00 %	$270	$278	$287	$295	$304	$409	$637	$856	$881	$908	$935
Total Generation Cost		**$3,195**	**$3,312**	**$3,435**	**$3,563**	**$3,698**	**$5,440**	**$10,416**	**$16,999**	**$17,901**	**$16,793**	**$17,654**
Profit (Loss)		$(1,104)	$(1,159)	$(1,217)	$(1,279)	$(1,344)	$(2,277)	$(5,488)	$(10,377)	$(11,080)	$(9,767)	$(10,417)
CPI (Inflation Rate)		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%

APPENDIX 1 - Aesthetic Flow Tables

CFS Available for Power Generation

	Monthly Mean CFS (1)	Aesthetic Flow Requirement				
		0	10	10 - 30	100	300
January	659	659	649	649	559	359
February	682	682	672	672	582	382
March	746	746	736	736	646	446
April	2,086	1,600	1,600	1,600	1,600	1,600
May	7,825	1,600	1,600	1,600	1,600	1,600
June	8,597	1,600	1,600	1,600	1,600	1,600
July	2,965	1,600	1,600	1,600	1,600	1,600
August	916	916	906	886	816	616
September	596	596	586	566	496	296
October	697	697	687	687	597	397
November	938	938	928	928	838	638
December	798	798	788	788	698	498

1, Source: FERC, ENVIRONMENTAL ASSESSMENT FOR HYDROPOWER LICENSE, Enloe Hydroelectric Project, FERC Project No. 12569, August 2011, pp. 37.

MWH of Power Generation

	Aesthetic Flow Requirement (CFS)				
	0	10	10 - 30	100	300
January	2,377	2,341	2,341	2,016	1,295
February	2,460	2,424	2,424	2,099	1,378
March	2,691	2,655	2,655	2,330	1,609
April	5,771	5,771	5,771	5,771	5,771
May	5,771	5,771	5,771	5,771	5,771
June	5,771	5,771	5,771	5,771	5,771
July	5,771	5,771	5,771	5,771	5,771
August	3,304	3,268	3,196	2,943	2,222
September	2,150	2,114	2,042	1,789	1,068
October	2,514	2,478	2,478	2,153	1,432
November	3,383	3,347	3,347	3,023	2,301
December	2,878	2,842	2,842	2,518	1,796
Total Ann. MWH	44,842	44,553	44,409	41,956	36,185