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2016
3rd 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

Columbia River Bioregional Education Project
Columbiana

July 1, 2016

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EXECUTIVE SUMMARY

Enloe Dam is located on the Similkameen River in north-central Washington, approximately four miles upriver from the town of Oroville. The dam was completed in the early 1920's, and produced hydropower until the project was decommissioned in 1958.[1] Since that time, the dam and its related power-generating facilities have sat dormant, although the owner of the dam, the Okanogan Public Utility District (OPUD), has attempted to re-energize Enloe four times over the years. OPUD began its most recent effort to update and repower the project in 2005 with a proposal to modify and upgrade the dam. OPUD submitted a Final License Application for re-energizing Enloe Dam on August 22, 2008, and the Federal Energy Regulatory Commission (FERC) issued a new license for the project on July 8, 2013. OPUD proposes to increase the annual generation at Enloe to 45,000 MWH, up from its original annual output of 22,500 MWH.

In its 2008 Final License Application, OPUD estimated that it would cost $31 million to construct the project. In 2011 Rocky Mountain Econometrics (RME) reviewed OPUD's FERC application, and noted that OPUD had failed 1) to predict the sharp downturn and lower long-term open market energy prices, and 2) to recognize the aesthetic value of Similkameen Falls, which are located immediately downstream of the dam. OPUD's omission of these issues meant that the cost of power generated by the proposed project would be more expensive than anticipated. While OPUD initially estimated that power from Enloe would be $9.79 / MWH cheaper than power on the open market, RME's 2011 review showed that the cost of power generated by the proposed project would actually be $31.16 / MWH <u>more</u> than power purchased on the open market.

In 2014, RME reviewed the Enloe project a second time, and reported that inflation would drive the cost of the project up to about $38 million. And, contrary to OPUD predictions, the price of open market power at MID-C (OPUD's least cost alternative) had decreased by fifty percent or more. Not only had open market prices precipitously declined, they were showing no signs of a major upturn.

In 2014, RME also detailed the impact of the uncertainty surrounding Enloe's ultimate level of energy production. The Department of Ecology (DOE) has set initial flows at 10/30 cfs. The actual flows required for aesthetic purposes will be determined by the DOE after studying three years of power house operations.

[1] *Federal Energy Regulatory Commission,* Notice of Availability of Final Environmental Assessment Environmental Assessment, Public Utility District No. 1 of Okanogan County, Washington, Project No. P-12569, p. viii, (August 31, 2011) (FERC eLibrary Accession No. 20110831-3040)

Even if the aesthetic flows were only 10-30 cfs, construction cost increases would drive the cost electricity produced at Enloe to about $47 / MWH more than energy purchased on the open market. If aesthetic flows in excess of the 10-30 cfs were required, Enloe production costs per MWH would be higher still. At an aesthetic flow of 300 cfs, the cost of power from Enloe would reach $102 / MWH, which is more than double the cost of open market power.

RME's 2016 analysis shows the cost of constructing Enloe Dam has continued to increase since the 2014 review. OPUD submitted a revised estimate of construction costs in their November 17, 2014 Enloe Power Point presentation. OPUD estimated the cost of the proposed power house at between $39 million and $45 million.

In addition to this new and increased cost of construction, OPUD also revealed that it had invested $13 million from general revenues towards the project between 2010 and 2015.

OPUD's budget for 2016 proposes an additional $1.3 million of general funds be spent on Enloe, bringing total pre-construction spending on the project by the end of 2016 to $14.4 million.[2] OPUD refers to these additional, pre-construction costs as "sunk costs." When taking these costs into account, total spending on Enloe would be at least $53.4 million, and could easily reach $59.4 million or more.

There are three possible future cost scenarios for the project. The least restrictive future for Enloe Dam assumes that the cost of construction is $39 million ignores pre-construction "sunk cost" spending, and assumes that aesthetic flow requirements will be as lenient as possible. Under this scenario, power produced by Enloe Dam will cost about $83 / MWH. This is more than double the price of power on the open market.

The next scenario assumes that the cost of construction remains $39 million, includes a 10/30 cfs aesthetic flow and $14.4 million in preconstruction "sunk cost" spending by the end of 2016. Under this scenario, the cost to produce power at Enloe Dam will be about $110 / MWH. If this scenario proves accurate OPUD ratepayers will be paying close to three times the cost of open market power.

The worst-case scenario assumes that total cost will be $59.9 million. This includes construction costs of $45 million, $14.4 million in preconstruction "sunk cost" spending, and assumes the highest possible aesthetic flow of 300 cfs. Under this scenario, the cost to produce power at Enloe Dam will be about $149 / MWH. If this alternative comes to pass, OPUD ratepayers will be paying nearly four times as much for Enloe energy than power purchased on the open market.

[2] See Appendix 3.

The issues that RME outlined in our 2011 and 2014 reports remain today. These include:

- Inflation has driven up the cost of Enloe Dam construction.
- The cost of acquiring power on the open market has not inflated.
- There is still no determination regarding the amount of water that would be required for aesthetic flows, and it remains uncertain how much power Enloe would ultimately produce.
- The total costs for the project are ballooning to as much as $59 million, which is about double the original cost estimate. The ratepayers will be responsible for paying these costs.

ENLOE DAM ENERGY PRODUCTION COST ESTIMATE

OPUD's application to FERC lists the cost of constructing Enloe as $31 million.[3] In 2014 RME estimated that inflation would increase the cost of the project to about $38 million. In November of 2014 OPUD reviewed the project and concluded that inflation would drive the cost of the project even higher, to about $39 million.[4]

2014 brought the awareness that the $39 million estimate was only for a portion of the project. As much as one-third of the cost of the project was, and is, being funded via yearly cash flow distributions as high as $3.1 million. The cost of Enloe, once thought to be $31 million, now appears to be headed for nearly double that amount, perhaps more.

None of the FERC application documents mention that OPUD intended to finance a large portion of the project from annual cash flows. Consistent with the FERC application, RME assumed OPUD's annual spending on Enloe was a part of, rather than an addition to, the $31 million FERC estimated cost. OPUD's 2014 PowerPoint presentation[5] showed RME's assumption to be invalid.

The first mention that OPUD was spending significant amounts of money on Enloe above and beyond the $31 million construction cost estimate was in a 2014 PowerPoint presentation to the OPUD Board of Commissioners. In that presentation total cost for Enloe is listed as $50.2 million, with the cost to complete the project listed as $39.1 million. Inflation can only account for the increase in cost from the original $31 million to the $39.1 million cost to complete. Sunk Costs are listed as $11.1 million

It is normal and customary for utilities to spend a portion of their administrative costs investigating and maintaining plans for servicing future load growth. These activities are usually called something like Integrated Resource Plans (IRPs). And, it is not unusual for IRPs to delve superficially into the specifics of potential future resources.

In the event that a particular new generation project is identified as needed and the decision is made to pursue said project, it is appropriate to establish an account for the project and direct all costs associated with the project towards that account. This includes all consulting, planning and permitting costs as well as the ultimate brick and mortar construction costs. The planning and permitting costs are a component of the ultimate capital cost of a project the same way that the cost of an engineering drawing is an essential part of the fabrication of a generator or a turbine.

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[3] 144 FERC ¶ 62,018 ,UNITED STATES OF AMERICA, FEDERAL ENERGY REGULATORY COMMISSION Public Utility District No. 1 of, Okanogan County, Washington, Project No. 12569-001, ORDER ISSUING NEW LICENSE, (July 9, 2013).
[4] Board of Commissioners Meeting, Enloe Hydroelectric Project, Public Utility District No. 1 of Okanogan County, November 17, 2014
[5] Ibid.

Table1, Enloe Dam Production Cost Possibilities

		OPUD Scenarios[6]			RME Scenarios[7]			
	Scenarios	1	2	3	4	5	6	7
Notes	Title / Description	Enloe 2014 (Minus Sunk)	Enloe 2014 Adverse Cost (Minus Sunk)	Enloe 2014 Adverse Cost (w / Sunk)	RME 10-30 (w / Sunk Thru 2016)	RME 100 (w / Sunk Thru 2016)	RME 300 (w / Sunk Thru 2016)	RME 300 (w / Sunk Thru 2016)
	Date of Estimate	2014	2014	2014	2016	2016	2016	2016
	Capital Cost ($1,000)	$39,100	$45,500	$56,560	$53,500	$53,500	$53,500	$59,900
1	Levelized Ann. Operating Cost ($1,000)	$3,684	$4,236	$5,190	$4,926	$4,926	$4,926	$5,478
2	Est. Avgas Ann. MWH	44,963	44,963	44,963	44,963	42,246	36,705	36,705
3	Operating Cost ($/MWH)	$81.93	$94.21	$115.43	$109.56	$116.61	$134.21	$149.25

Table 1, above, presents 7 production cost scenarios for Enloe dam. Scenarios 1 – 3 are taken almost verbatim from OPUD's 2014 PowerPoint presentation. They show the cost of construction ranging from $39.1 million without sunk costs to as much as $56.6 million with potential cost overruns and the inclusion of sunk costs. These construction costs will result, respectively, in annual operating costs ranging from a low of $3.7 to $5.2 million. Under the least restrictive esthetic flow requirement, the 10-30 alternative, the project will generate about 45,000 aMwh of energy. Dividing the annual operating costs by the annual generation results in the potential energy from Enloe costing somewhere between $82 and $115 per MWH. To reiterate, these three scenarios close reproductions of OPUD's analysis.

Scenarios 4 – 7 are RME scenarios. These scenarios build on the cost estimates provided in OPUD's 2014 PowerPoint presentation. They also incorporate the effect of reduced levels of generation as a result of pending determinations regarding required esthetic flow requirements.

Scenarios 4 – 6 each use total capital cost of $53.5 million as a starting point. This is based on $39.1 million construction cost plus $14.4 sunk costs through the end of 2016. These construction costs will result in annual operating costs of $4.9 million. Under the least restrictive esthetic flow requirement, the 10-30 alternative, the project will generate about 44,963 aMwh of energy. Under the most restrictive scenario, the requirement for 300 cfs esthetic flows will limit energy output to 36,705 aMwh. Dividing the annual operating costs by the annual generation results in the potential energy from Enloe costing somewhere between $109 and $134 per MWH.

Scenario 7 presents a worst-worst production cost scenario. In this case, OPUD's adverse cost estimate of $45.5 million is added to sunk costs of $14.4 through 2016 for a total cost of $59.9

[6] Ibid.

[7] Source, OPUD and RME.

million. This generates an annual operating cost of $5.5 million. Under the most restrictive, 300 cfs, flow alternative there will be only 36,705 aMW to absorb annual costs resulting in Enloe energy costing $149 / MWH.

To summarize, it appears that the $31 million cost estimate in the FERC application only refers to the brick and mortar portion of Enloe dam. Inflation since 2007 has driven this cost up to about $39 million and potentially more. Off budget spending on Enloe beginning in about 2010 now totals in excess of $13 million. The budget for 2016 proposes an additional $1.3 million to be spent on Enloe, bringing total cash flow spending on the project at the end of 2016 to about $14.4.[8] Adding the latter amount to the brick and mortar portion brings the total potential cost of the project to at least $53 million. <u>Under the least stringent esthetic flow scenario, the 10-30 cfs option, the cost to produce Enloe power will be about $110 / MWH.</u>

A worst-worst scenario that includes the cost over-runs documented in the 2014 PowerPoint by OPUD, the $14.4 cash flow spending from budgets 2010 – 2016, and the 300 cfs esthetic flow restrictions, will result in power produced by Enloe Dam costing about $149 / MWH.

[8] See Appendix 1

LEAST COST ALTERNATIVE POWER - OPEN MARKET ENERGY

In this section RME will show that open market energy is a cheap and reliable source for the equivalent amount of energy that Enloe would produce.

Pacific Northwest Power Resources

Table 2, below, illustrates total annual average northwest energy portfolio of 28,900 aMW.

Table 2, Pacific Northwest Energy Supply Sources[9]

Resource	Pacific NW Regional Annual Energy Resources (aMwh)	Percent of Total
Hydro	11,862	41.0%
Large Thermal and Combustion Turbines	11,851	41.0%
Cogeneration and Renewables	4,418	15.3%
Imports, Small Thermal & Misc.	769	2.7%
Total PW Regional Resources	28,900	100.0%

Source White Book 2014 pp. 43

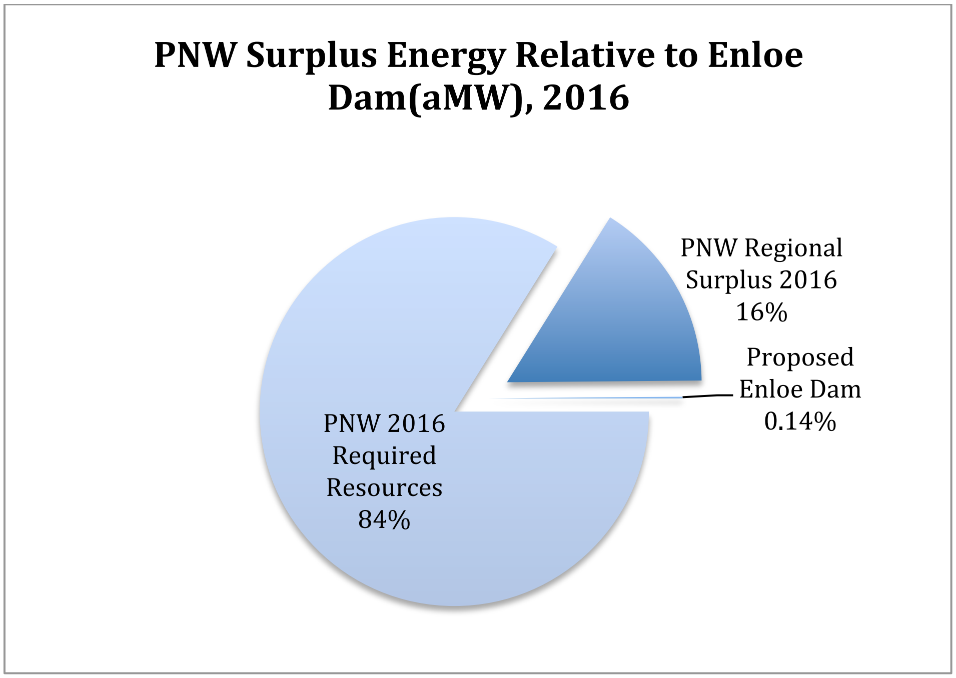
In 2016, the Pacific Northwest will use about 84 percent of its energy generating potential.

Table 3, Pacific Northwest Energy Surplus Quantities[10]

Enloe v Surplus Energy	2016	%
PW Regional Surplus 2016	4,616	15.97%
Proposed Enloe Dam	40	0.14%
PNW 2016 Required Resources	24,244	83.89%
Total PNW Regional Resources	28,900	

[9] Source: Bonneville Power Administration, 2014 Pacific Northwest Loads and Resources Study, January 2015, Table 1-6, PNW Regional Resources, OY 2016, 1937-Critical Water Conditions, pp.12, and RME.
[10] Source White Book 2014 pp. 43

Chart 1, Pacific Northwest Energy Surplus



At roughly 40 aMW of generation on a good year, Enloe dam would amount to less than two-tenths of one percent of total northwest capacity. If built, the dam would only amount to 0.87% of northwest surplus generation.

More simply, Enloe Dam relative to either the generating capacity of the rest of the northwest, or to the more limited surplus capacity in the northwest, is simply too small to have any measureable impact. In calculations relative to sourcing Enloe amounts of energy via the open market, Enloe is a non-factor.

Open Market Price Expectations

The six year span from 2002 to 2008 saw western open market prices slightly more than double from about $30 / MWH to about $70 / MWH in 2008, the year of the crash.

The rate at which open market energy prices inflated was extreme by historical standards but not as extreme as the rate at which they deflated during the recession.

While it took 6 years for open market energy prices to increase from $30 to $70, it only took one year for them to drop all the way back down. The recession undoubtedly deserves much of the credit for the price decline, but other factors came into play as well. In addition to static or even declining demand, significant new amounts of wind generation, solar generation and other resources in the NW also get credit. The addition of significant amounts of wind and solar is important in this context because they have very low, perhaps zero, marginal generation cost. This is in addition to the pre-existing situation whereby the west in general and the northwest in particular are hydropower intensive. Similar to wind and solar, hydropower also has minimal marginal production cost.

The issue of zero, or near zero, marginal production cost is important. Energy markets such as MIDC or NP15 are open markets, similar to auctions. Prices in these markets are based on marginal costs and unlike regulated utilities the price of energy in these markets is not required to recover fixed costs.

In these markets willing sellers offer energy to willing buyers at whatever price the parties agree. If prices are too low for a seller to recoup their variable costs, things like fuel costs, they will usually not put their power for sale on the market. If prices are high enough that a seller can cover their variable costs, and at least some of their overhead, they will offer their power in this market. They obviously would prefer to sell at higher prices than at lower prices. However, selling at prices that cover all their variable costs and at least some of their overhead is better than not selling anything at all. Without the requirement of cover fixed costs energy in these markets routinely sells in the teens or low single digits.

On average, in the northwest, energy supply exceeds demand by about 16 percent. That number is higher most nights, and substantially higher in the spring when rivers are at peak runoff. During those times utilities flood the market with their surplus power at bargain basement prices. There is less surplus energy available during peak hours, particularly during late summer when river flows are lower. However, there is ample surplus energy to supply the minor amounts of energy we are talking about for OPUD. And on average, energy prices remain low.

Chart 2, Price History Comparison, FERC and Open Market

Sources: CAISO[11], FERC[12], and RME.

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

In 2008, NP15 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.

Since RME's review of this subject in 2014, prices have been as high as the mid $40s, and as low as $28 for full years. The price of energy at NP15 in 2015, at $32.45 / MWH, was the forth lowest in the past 14 years.

For a working number for this analysis RME looked at the average for the past 14 years, the trend for the past 14 years, and the trend for the post recession years, 2009-2015.

Open market NP15 day ahead energy prices were $26.39 / MWH in 2002. Six years later prices had escalated to $70.44 for 2008, before crashing back down to $35.11 the following year. Since then, price variations have stayed in a much narrower range, between $28.32 in 2012 and $40.70 in 2014. The average for the full 14 year period is $40.88 / MWH.

If we look at the trend line associated with NP15 prices since 2002 we see a downward sloping line with a value of $39.19 / MWH in 2015. RME is an admitted proponent of open market energy for utilities with modest means. At the same time, RME is hesitant to hang its hat on long term downward sloping price curves.

Table 4, Price History Comparison, FERC and Open Market

Year	NP 15 Avg. Ann. Price	Trend 2009 - 2015	Trend 2002 - 2015	FERC Price Est.
2002	**26.39**		**42.58**	
2003	**35.02**		**42.32**	
2004	**38.54**		**42.06**	
2005	**54.74**		**41.80**	
2006	**43.47**		**41.54**	
2007	**54.79**		**41.27**	**66.00**
2008	**70.44**		**41.01**	**67.00**
2009	**35.11**	**32.95**	**40.75**	**68.00**
2010	**35.78**	**33.82**	**40.49**	**69.00**
2011	**30.01**	**34.70**	**40.23**	**70.00**
2012	**28.32**	**35.57**	**39.97**	**71.00**
2013	**40.60**	**36.44**	**39.71**	**72.00**
2014	**46.70**	**37.31**	**39.45**	**73.00**
2015	**32.45**	**38.19**	**39.19**	**74.00**
Average	40.883			

Sources: CAISO,[13] FERC[14], RME.

[12] Op. Cit. 1.

[13] Op. Cit. 20.

[14] Op. Cit. 1.

In effort to separate post economic crash numbers from the longer price curve RME looked at the price trend beginning in 2009. For the seven-year period 2009 through 2015 the NP15 price curve is upward sloping and gains about 2.65 percent per year. In other words, open market energy prices have increased at about the same rate as inflation for the past 7 years.

RME finds it interesting that three separate statistical approaches arrive at a range of prices separated by only \$2.69 / MWH. With a high of \$40.88 and a low of \$38.19, for the purposes of this analysis, RME took a middle point of \$40.00 / MWH to use as the alternative energy cost to compare against the various Enloe Dam Scenarios.

To summarize, RME admits that open market prices are more volatile than the known price of a fixed investment such as Enloe. However, the most optimistic estimate for the cost of Enloe power is worse than the worst full year average of open market prices in the past 14 years.

ENLOE DAM – PROFIT (LOSS) ESTIMATION

Table 4 below reprises Table 1 on page 6 and adds additional rows at the bottom for the purpose of comparing estimated Enloe production costs to open market prices.

Looking at the three OPUD scenarios on the left, Enloe Dam production cost is estimated to range from a low of $81.93 to a high of $115.43. With open market alternative power costing only $40 / MWH, Enloe, under these three scenarios, will lose between $42 and $75 on each MWH of energy it produces. On an annual basis under these three scenarios, if Enloe is built, OPUD will be spending between $1.9 million and $3.4 million more for energy than if they sourced the same amount of power on the open market.

Table 5, Enloe Dam Production Cost Estimates

		OPUD Scenarios			RME Scenarios			
	Scenarios	1	2	3	4	5	6	7
Notes	Title / Description	Enloe 2014 (Minus Sunk)	Enloe 2014 Adverse Cost (Minus Sunk)	Enloe 2014 Adverse Cost (w / Sunk)	RME 10-30 (w / Sunk Thru 2016)	RME 100 (w / Sunk Thru 2016)	RME 300 (w / Sunk Thru 2016)	RME 300 (w / Sunk Thru 2016)
	Date of Estimate	2014	2014	2014	2016	2016	2016	2016
	Capital Cost ($1,000)	$39,100	$45,500	$56,560	$53,500	$53,500	$53,500	$59,900
1	Levelized Ann. Operating Cost ($1,000)	$3,684	$4,236	$5,190	$4,926	$4,926	$4,926	$5,478
2	Est. Avgas Ann. MWH	44,963	44,963	44,963	44,963	42,246	36,705	36,705
3	Operating Cost ($/MWH)	$81.93	$94.21	$115.43	$109.56	$116.61	$134.21	$149.25
4	Open Market Price for Power ($/MWH)	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00
5	Value of Enloe Power Production ($1,000)	$1,799	$1,799	$1,799	$1,799	$1,690	$1,468	$1,468
6	Profit (Loss) (Relative to Alternative Power) ($1,000)	$(1,885)	$(2,437)	$(3,391)	$(3,128)	$(3,236)	$(3,458)	$(4,010)
7	Profit (Loss) ($/MWH)	$(42)	$(54)	$(75)	$(70)	$(77)	$(94)	$(109)

Looking at the four RME scenarios on the right, production cost is estimated to range from a low of $109.56 to a high of $149.25. With open market alternative power costing $40 / MWH, Enloe will lose between $70 and $109 on each MWH of energy it produces. On an annual basis under these four scenarios, if Enloe is built, OPUD will be spending between $3.1 million and $4 million more for energy, every year for 40 years, than if they sourced the same amount of power on the open market.

Chart 3, Enloe Dam Operating Cost vs. FERC Thermal and Open Market Energy

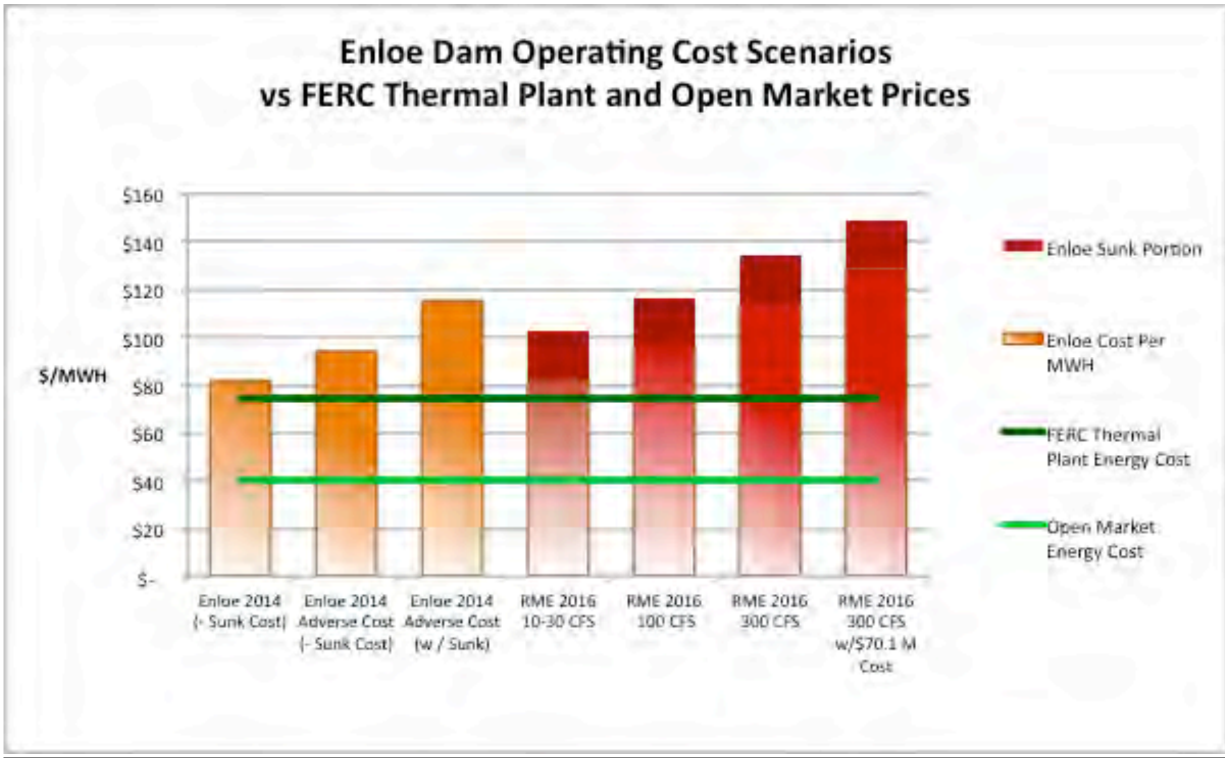


Chart 3 above graphically presents the finding in Table 5 on the previous page. Additionally this chart also shows both the open market and FERC price hurdles Enloe energy needs to stay under for Enloe to be deemed a desirable investment.

If we ignore sunk costs, and the possibility of a substantial requirement for esthetic flows over the falls, Enloe power will cost about $83 / MWH. That is what Enloe power will cost, every year for the next 40 years. At that level, it is reasonably close to the FERC's alternative cost of $79 per MWH. However, at $83 / MWH, best case Enloe will be more than double the average cost of open market power. It will even be higher, by $13 / MWH, than the worst-case open market power in the last 14 years at $70 / MWH.

At the right hand end of the list of scenarios, the worst-worst case shows Enloe energy costing $149 / MWH. If built, that will mean Enloe power will come in at 270% higher than energy readily available on the open market.

APPENDIXES

Appendix 1, Could OPUD run Enloe at a loss while the construction debt is being retired and then become profitable in later years?

This is a common belief among energy developers, particularly hydroelectric developers.

The issue, in economic terms, is whether or not the developer can ever get "in front" of the interest on the original debt.

The general idea is that, if a developer can build a project, and 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 become sufficiently profitable that it makes up for all the previous year's losses.

The concept is technically possible but in practice the occurrence is rare. 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 pile of debt gets bigger and bigger to the point where the accumulated debt becomes bigger, much bigger than the original investment.

For a project to successfully follow this path the interest rate has to be low, the annual losses have to be minimal, the time period of initial losses has to be short (usually less than 5 years) and the post–debt-payoff profitability has to be high. Enloe fails on every factor except the interest rates.

Anyone who has looked at an annuity knows how this works. If you put a sum of money in a savings account each year for decades at a time, the accumulated total, plus interest will result in a surprisingly large amount after the passing of three or four decades. The same is true in reverse. If the loses are incurred each year, for decades at a time, the resulting pile of debt, plus interest, will be disturbingly large after the passing of several decades.

The example presented in Table 7 below illustrates the problem. This example assumes the project produces 44,409 MWH of energy. In the first year of operation the avoided cost price of power (NP 15 Open Market Power) is $40 / MWH, and revenues are $2.1 million per year. The Capital cost of the plant is $39.1 million that, at 4.5% interest for 40 years, requires an annual payment of $2.125 million. Insurance, taxes, M&O, etc. bring total year one operating costs to $3.3 million. This results in a net loss in the first year of operation, relative to open market prices, of $1.5 million. In following years all costs and all prices, with the exception of the fixed construction loan and the loan for environmental features, are inflated at 3% per year. The loans for construction and environmental features remain fixed for the life of the loans.

Another simplifying assumption, in Enloe's favor, is that there will be no need for additional capital expenditures for such things as repair and replacement of control gates, turbines, substations, etc., ever.

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 would be 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.

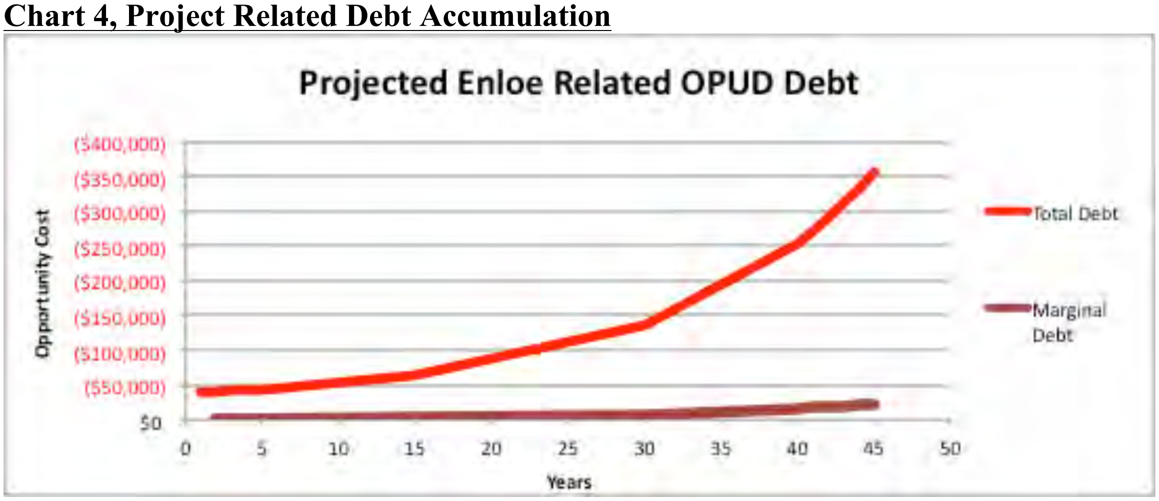
In the first few years of the project, the problem does not appear to be too severe. Losses in year one are $1.5 million. In years two through five the annual losses continue to get a little bigger but they still seem manageable. Total debt in the line of credit in year 5 is has grown to $6.4 million.

The problem starts to become more evident out around year 15. At that point, even though the annual losses are only up to the $2.5 million range, the year after year accumulation, plus interest, is starting to pile up. In year 15 the line of credit is up to $31.4 million, within 20 percent of the construction cost of the dam.

By year 30 it is clear things are have gotten out of hand for OPUD ratepayers. In year 30 the annual accumulation of debt, and interest on the debt, has driven debt in the line of credit account to $118 million, more than triple 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 $9.6 million, roughly 6 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 the end of year 40, or the beginning of year 41. That is the good news. That means the annual debt service associated with that debt, $2.1 million per year would cease. The bad news is the debt in the line of credit account will have risen to $273 million, which is more than 7 times the original construction cost. At that point the project will be losing about $20 million per year and the amount will keep going up until the line of credit devours OPUD. The result is presented graphically in Chart 4 below.

Chart 4, Project Related Debt Accumulation



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.

Table 6, OPUD Dept. Accumulation Example - Original Debt Payoff in 40 Years

Year		**1**	**2**	**5**	**15**	**30**	**40**	**41**	**42**	**43**	**44**
Annual Generation (MWH)		45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000
Open Market Price		$0.04	$0.04	$0.05	$0.06	$0.09	$0.13	$0.13	$0.13	$0.14	$0.14
"Revenue"		$1,800	$1,854	$2,026	$2,723	$4,242	$5,701	$5,872	$6,048	$6,229	$6,416
Plant Investment											
Plant Investment Debt		$39,100	$38,735	$37,537	$32,184	$18,122	$2,033				
Annual Cost											
I. Construction Debt Service											
a. Interest on Capital	**4.5%**	$1,760	$1,743	$1,689	$1,448	$816	$91				
b. Capital recovery cost (40yr, 4.5%)	0.93%	$365	$382	$436	$677	$1,309	$2,033				
Total Plant Debt Service		$2,125	$2,125	$2,125	$2,125	$2,125	$2,125				
			$747	$1,999	$7,593	$22,287	$39,100				
Line of Credit - Operating Debt											
Total Operating Debt			1,453	6,379	31,415	118,901	253,421	272,824	291,526	311,597	333,140
a. Interest on Capital	**4.5%**		65	287	1,414	5,351	11,404	12,277	13,119	14,022	14,991
b. Capital recovery cost (20yr, 5.5%)			46	203	1,001	3,790	8,078	8,697	9,293	9,933	10,619
Total Op. Debt Service			112	490	2,415	9,141	19,482	20,974	22,411	23,954	25,611
II. Insurance	0.2%	$76	$78	$86	$115	$179	$241	$248	$256	$263	$271
III. Taxes - Privilege Tax (% of first 4 mills/kWh)	5.4%	$10	$10	$11	$15	$23	$30	$31	$32	$33	$34
IV. Operation and Maintenance (1.9% of Invest Cost)		$737	$759	$830	$1,115	$1,737	$2,335	$2,405	$2,477	$2,551	$2,628
V. Environmental Measures (40yr, 4.5%)		$35	$35	$35	$35	$35	$35	$35	$35	$35	$35
VI. Administrative and General/Contingency	35.%	$270	$278	$304	$409	$637	$856	$881	$908	$935	$963
Total Generation Cost		**$3,253**	**3,397**	**$3,880**	**$6,228**	**$13,876**	**$25,103**	**$24,574**	**$26,119**	**$27,772**	**$29,542**
Profit (Loss)		$(1,453)	$(1,543)	$(1,854)	$(3,505)	$(9,634)	$(19,403)	$(18,702)	$(20,071)	$(21,543)	$(23,126)
CPI (Inflation Rate)		3%	3%	3%	3%	3%	3%	3%	3%	3%	3%

Appendix 2, Could OPUD sell Enloe production as "green" power and receive premium prices? Alternately, could Enloe provide extra value, and receive higher prices as a backstop to wind or solar projects?

A. It appears unlikely that OPUD could try to sell Enloe power as green power. Green-e, the green power certificating agency, remains skeptical of conventional hydro projects like Enloe. Green-e rules exclude projects that, "… increase water storage capacity or the head of an existing water reservoir," which would exclude Enloe.[15]

B. In the unlikely event Enloe managed to qualify as green power the next question is whether or not the premium would be enough to cover Enloe's losses. Referring back to Table 5, Enloe, as currently configured, would lose between $70 and $109 per MWH of production depending on the required level of esthetic flow. For green power premiums to move Enloe into the realm of profitability, green power premiums would have to be high enough to cover those losses. The highest green power premium on record is $60 / MWH for a solar plant in California. The average premium in Washington and neighboring states is much lower, at $16.45 / MWH. Given those numbers, it is very unlikely that a green power premium would be sufficient to make Enloe profitable.

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

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[15] http://www.green-e.org/docs/energy/Appendix%20D_Green-e%20Energy%20National%20Standard.pdf, pp. 2 – 3.

Table 7, Green Power Premiums[16]

State	Type	$ / MWH	Statistical Measure	Green Power (Hydro) Premium ($ / MWH)
CA	wind, solar	15.00	Avg.	16.45
CA	various renewables	20.00	Med	15.00
CA	wind, hydro and PV	30.00	Mode	15.00
CA	100% renewable	10.00	Max	60.00
CA	100% local solar	60.00	Min	0.90
CA	wind, PV	15.00		
ID	wind, solar and biomass	3.50		
ID	wind	19.50		
MT	wind, PV	20.00		
MT	various renewables	0.90		
MT	wind, hydro	12.50		
MT	wind	11.00		
OR	PV, wind	20.00		
OR	wind	15.00		
OR	wind and landfill gas	8		
OR	various renewables	12.5		
OR	wind	15.00		
OR	landfill gas	19.00		
OR	wind, landfill gas, low-impact hydro	8.00		
OR	wind	3.00		
OR	various	10.00		
WA	wind, solar and biomass	3.50		
WA	landfill gas	17.00		
WA	PV, wind	15.00		
WA	wind, PV	8.00		
WA	wind	20.00		
WA	wind, hydro	40.00		
WA	landfill gas	10.50		
WA	wind	15.00		
WA	wind, hydro, biogas, solar	12.50		
WA	geothermal, biomass, wind, hydro	15.00		

[16] http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml, Source: National Renewable Energy Laboratory, Golden, Colorado., Notes: Utility green pricing programs may only be available to customers located in the utility's service territory.

The current minimum premium for hydro green power is $0.90 / MWH in Montana. The average premium, $16.45 / MWH, the Median premium, $15 / MWH, and the most common premium, $15.00 / MWH, are all too low to move Enloe into profitable territory relative to open market prices of $40 / MWH

C. What about the potential for Enloe to provide backup reserve capacity for wind or solar projects and thus get higher prices?

The concise answer is that this is not a good fit for Enloe. For hydro to be a good symbiotic fit with wind the project has to 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 be able 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 small project with a small reservoir the length of time Enloe can throttle the project up or down is extremely limited. And, at 9 MW, Enloe will be smaller than most state of the art wind farms, so Enloe cannot be of much help there.

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 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.

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[17] pp. A-13
[18] pp. B-18
[19] Project No. 12569-001, pp. 53

Appendix 3, Enloe Dam Detail in OPUD Budgets, 2010 – 2016[20]

OPUD Treatment of Enloe Dam in Budgets 2010 - 2016

Budget Year	Detail	Amount	Total Year	Notes
2010			$2,160,000	Enloe expenditures not mentioned in the summary. Total in the detail section is $2,160,000.
	Misc. Contractual Services			
	PUD Enloe Emergency Action Plan	$80,000		
	Enloe PM&Es (water rights, etc.)	$200,000		
	Enloe Road Repair	$200,000		
	Capital - Contractual Services			
	Enloe Dam - Entrix and Others	$1,600,000		
	Capital - Materials and Supplies			
	Enloe Dam - EAP	$50,000		
	Enloe Dam - EAP Equipment	$30,000		
2011			$2,010,000	Enloe listed at $1.9 million. The detail comes in a little bigger at about $2.01 million.
	Misc. Contractual Services			
	PUD Enloe Emergency Action Plan	$30,000		
	Enloe Maintenance and Repair	$200,000		
	Capital - Contractual Services			
	Enloe Dam - Engineering and Design	$500,000		
	Enloe Dam - License/Compliance/Permitting/Legal	$750,000		
	Enloe Dam - Construction	$500,000		
	Capital - Materials and Supplies			
	Enloe Dam - EAP	$30,000		

[20] Source, OPUD Budgets, 2010 – 2016.

Budget Year	Detail	Amount	Total Year	Notes
2012	Enloe Dam	$1,300,000	$1,300,000	Enloe appears in the summary, but not in the detail
2013	Enloe Dam	$3,100,000	$3,100,000	Enloe appears in the summary, but not in the detail
2014	Enloe Dam	$2,750,000	$2,750,000	Enloe appears in the summary, but not in the detail
2015	Enloe Dam $1,764,000.	$1,764,000	$1,764,000	Enloe in summary. Only about $30,000 shows up in detail.
2016			$1,338,000	Amount listed in summary is $1.056 million, roughly $300,000 less than mentioned in detail.
	Misc. Contractual Services			
	Enloe Dam Dewatering	$1,000,000		
	Enloe Dam Inspection	$38,000		
	Capital - Contractual Services			
	Enloe Dam - On Call Engineering Support	$300,000		
Total, 2010 - 2016			$14,422,000	

Appendix 4, Sunk Cost Discussion

There is a tendency to ignore sunk costs on the grounds that, since they are not recoverable, it is just as well to ignore them.

1. This is inappropriate because when a company has spent, and is continuing to spend money on a project, even if the spending is not recoverable, it represents real money being spent on behalf of ratepayers. OPUD rates could be lower if the money were not being spent.

2. If the spending is being dedicated to a given project, in this case Enloe Dam, it is more transparent to book it as such. In that manner both management and ratepayers can more easily focus on the degree to which the project is or is not desirable. It is only fair for ratepayers to know how much is going to be spent in this fashion. It seems reasonable that ratepayers should have been informed of the magnitude of off-budget cash flows that were, and are, being dedicated to Enloe. It would have been prudent to inform ratepayers that management was committing the utility to a power source that might result power costing at least $83 / MWH and perhaps as much $149 / MWH energy.

3. There is a tendency, after some poorly defined point in time, to use sunk costs as justification for going forward with projects. In the case of Enloe Dam, at this moment in time, this would be poor reasoning. As an analogy, a rafter may float for years down a river headed towards a waterfall and certain death. Regardless of the amount of time invested upstream, it always makes sense to get out of the river before the falls, even if it is only inches before the falls. In the case of Enloe, something in excess of $11 million has already been spent. Spending by the end of 2016 looks to be in excess of $14 million. Spending another $39 million, or more, on the physical structure would amount to throwing good money after bad. The debt service on just the $39 million portion will result in Enloe power costing $83.04 / MWH. That is more than double the price of readily available open market power.