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Lower Snake River Dam
Alternative Power Costs

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Rocky Mountain Econometrics
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Preface

Rocky Mountain Econometrics (RME) has been actively analyzing northwest energy issues since 1985. In the 1980s and 1990s, the author was the staff economist for the Idaho Public Utilities Commission.

In 1998 Governor Kempthorne, and later, Governor Batt, contracted with RME to monitor the Army Corp of Engineers' (ACOE) development of the FREIS[1] and the potential breaching of the four Lower Snake River Dams in Washington State (LSRD). In that capacity RME documented for Idaho's elected leaders the conclusions, errors and omissions in the ACOE's analysis.

In 2002 Northwest Resource Information Center and RME published, *"Idaho Economic Effects of Breaching/Not Breaching the Army Corps of Engineers' Snake River Dams in S.E. Washington."* That document details that much of the ACOE's findings in the FREIS were flawed and that the best economic alternative was to decommission the LSRD.

In early 2015 Idaho Rivers United asked RME to once again bring its expertise to the subject and revisit the FREIS for the purpose of calculating the cost of replacing the energy produced by the LSRD in current (2015) dollars. To that end, the following pages present the context in which the four Lower Snake River Dams in Washington State currently operate as energy producing entities within the greater Pacific Northwest region. The following pages also present scenarios for viewing the cost of replacing the electric power that would be lost if the dams are decommissioned.

[1] US Army Corps of Engineers, Walla Walla District, "Lower Snake River Juvenile Salmon Migration Feasibility Report/Environmental Impact Statement" (FREIS), 1999.

Executive Summary

The median electricity production of the four LSRD is about 795 aMW[2], about seven percent of the region's 11,000 aMW of hydropower capacity. While the NW is renowned for hydropower, hydro accounts for only a little more than one third of the region's total capacity of 28,900 aMW. Of system wide total energy, the LSRD account for less than 3 percent. The system is currently running at about 84% of capacity with about 4,600 aMW's of surplus energy.

If the LSRD dams were decommissioned today, capacity utilization would increase only slightly from about 84% to about 86.5%.

From that standpoint, the LSRDs are not of critical importance. Still, they are resources that are in continual use. In the absence of other actions, such as conservation, other resources would be substituted for them. It is reasonable to ponder the financial impact if alternative resources are brought online.

Jim Waddell, a recently retired ACOE engineer, calculates that it will cost $312.9 million annually[3] to maintain the dams, 90 percent of which, $281.6 million, is allocated for power generation. One of the simplest ways to replace the LSRD power is to purchase it on the open market. If that had been done from 2009 through 2014, it would have cost NW ratepayers, on average, $263 million per year, an annual savings of about $19 million. The $19 million reduction translates to a $0.06 reduction of a typical monthly residential power bill.

If utility scale photovoltaic energy is developed to replace the LSRD with energy purchased on the open market during nightime hours when PV's are not producing, the replacement power will likely cost about $260 million per year. This is $21.7 million less than it costs to maintain the LSRD. Monthly residential power bills will decrease by, again, about $0.06.

To summarize, the LSRDs are not needed from a capacity standpoint. From a cost standpoint there are options that result in lower cost power for NW ratepayers if the dams are removed.

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[2] An average megawatt (aMW) is the amount of electricity produced by the continuous production of one megawatt over a period of one year. The term, sometimes also called average annual megawatt, defines power production in megawatt increments over time. Because there are 8,760 hours in a year, an average megawatt is equal to 8,760 megawatt-hours

[3] The Costs of Keeping the Four Lower Snake River Dams: A Reevaluation of the Lower Snake River Feasibility Report, Jim Waddell, 2015, pp. 10.

The Lower Snake River Dams in the Context of Pacific Northwest Power Resources

The LSRD are physically large. Each dam is about 100 feet high and the combined reservoirs stretch half way across Washington State. However, physical size is a poor measure of energy generation potential.

The energy potential of a hydroelectric dam is a function of the amount of water that flows through the turbines and the height from which it falls. By the time the Snake River passes Lewiston much of its energy generating potential has already been spent. From Lewiston to Pasco, a distance of about 140 miles, the river only drops about 400 feet. Compare that to Grand Coulee dam at 550 feet tall on a far larger river.

The Lower Snake River Dams are neither a major or critical part of the northwest energy picture. Table 1 illustrates that the median generation of 795 aMW by the LSRD are only about 3 percent of the total annual average northwest energy portfolio of 28,900 aMW. Chart 1, on the following page, presents the data from Table 1 in a graphic format.

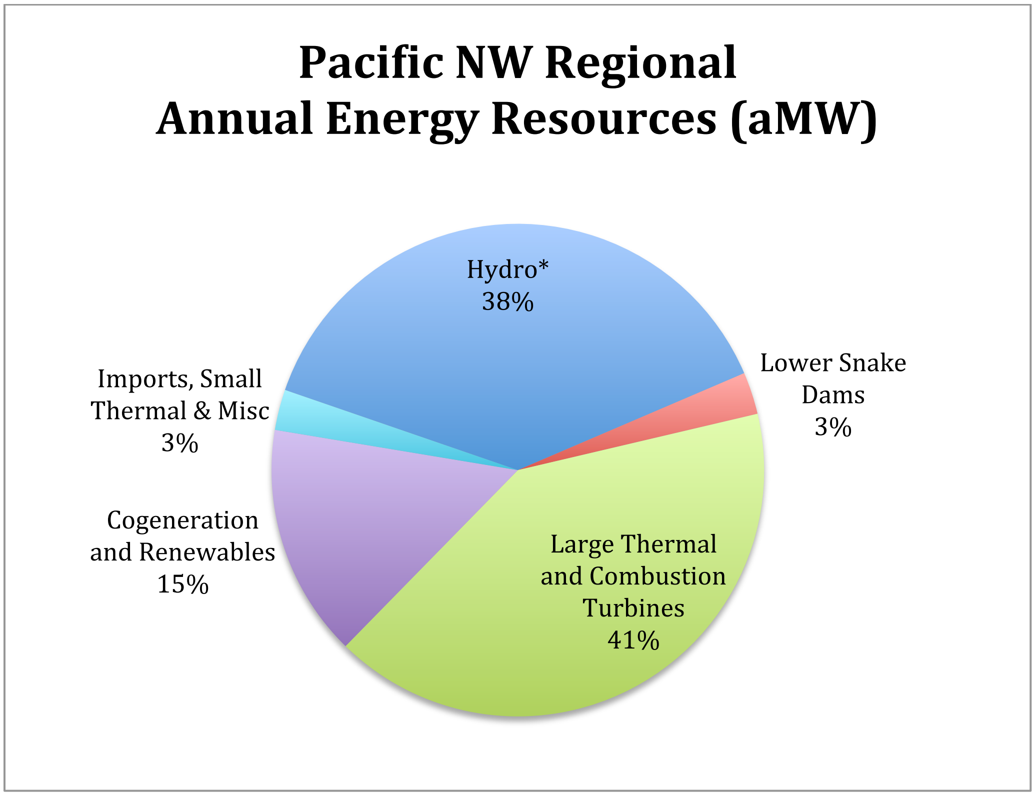
Table 1, Pacific Northwest Energy Resources[4]

Resource	Pacific NW Regional Annual Energy Resources (aMW)	Percent of Total
Hydro*	11,067	38.3%
Lower Snake Dams	795	2.8%
Large Thermal and Combustion Turbines	11,851	41.0%
Cogeneration and Renewables	4,418	15.3%
Imports, Small Thermal & Misc.	769	2.7%
Total PNW Regional Resources	28,900	100.0%

*Does not include LSRD.

[4] 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.

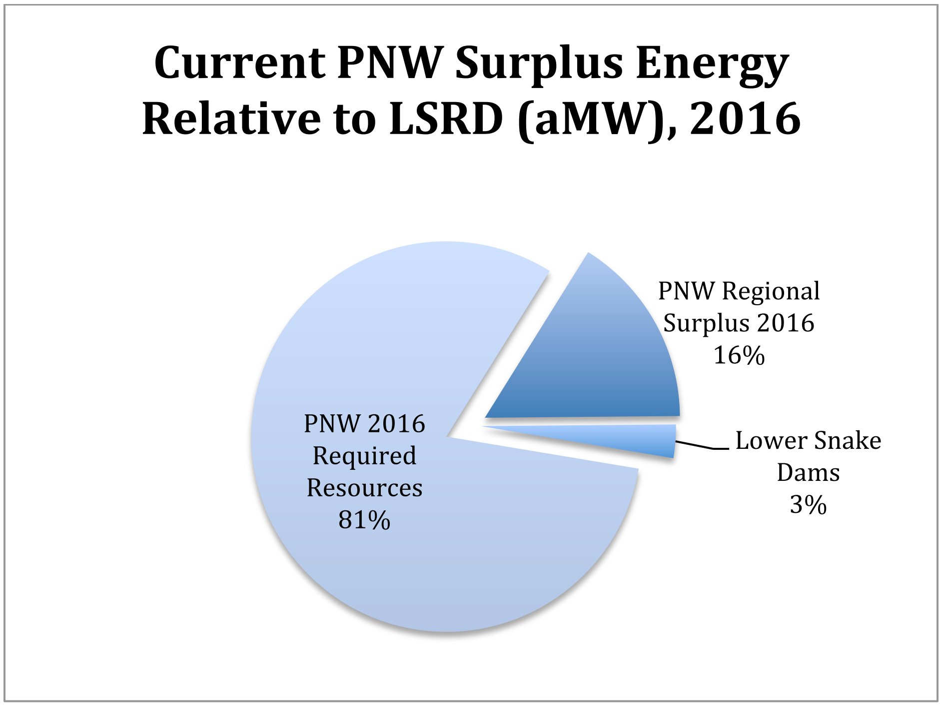
Chart 1, Pacific Northwest Energy Resources



*Does not include LSRD.

To put the energy produced into even better perspective, Chart 2, on the following page displays the LSRD energy production relative to the amount of surplus potential energy production in the region. In 2016, the Pacific Northwest will use about 84 percent of its energy generating potential. This includes energy from the LSRD.

Chart 2



By 2025 the NW Council and others project energy loads to grow and energy surpluses to be down to about 5 percent of total energy potential. Significantly, even then, the LSRD, or the absence of same, are not a critical part of the northwest energy picture. Even then, there will be sufficient surplus resources to accommodate energy loads even if the LSRD have been decommissioned and no other resources have been installed. Table 2, below, shows the LSRD relative to NW energy surplus in 2016 and 2025.

Table 2, Pacific Northwest Energy Surplus

LSRD v Surplus Energy	**2016**	**%**	**2025**	**%**
PNW Regional Surplus 2016	4,616	16%	1,343	5%
Lower Snake Dams	795	3%	795	3%
PNW 2016 Required Resources	23,489	81%	26,762	93%
Total PNW Regional Resources	28,900		28,900	

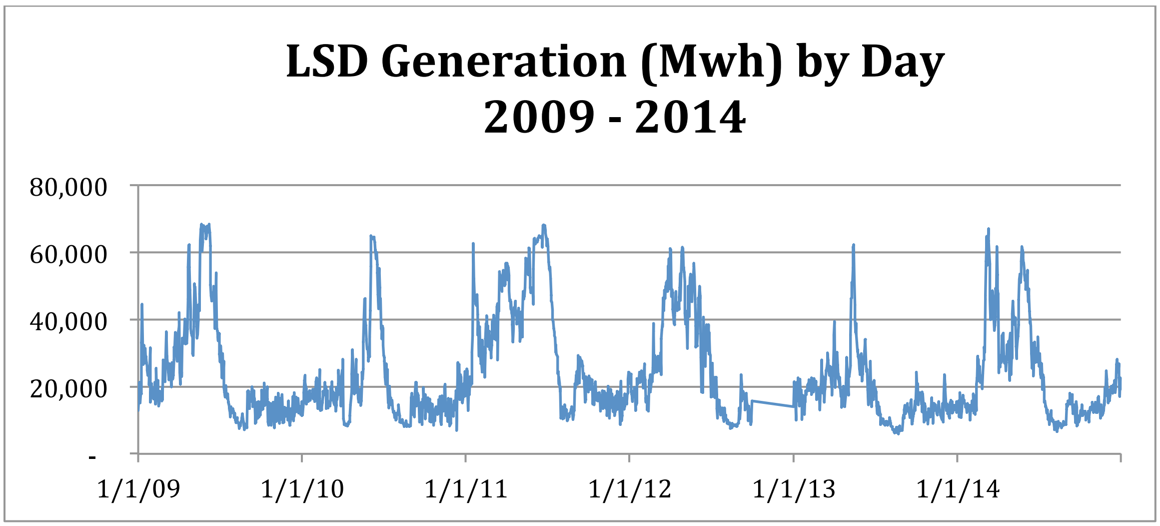
This is not to say that some alternative to the LSRD, generation, conservation, etc., will never be needed at some point in the future. It will. The bigger point is that it has always been the case that as long as energy loads continue to grow, new energy resources or other alternatives will continually be needed. This is true regardless of whether or not the LSRD remain in place. The only significant impact of removing the LSRD is that the critical point at which new resources are needed is one to two years sooner than would be the case if they were not removed. From a critical needs perspective the point at which the amount of power produced by the LSRD is absolutely necessary does not occur until sometime after 2025. And, as other new resources are brought online before 2025, just as new resources have been coming online every year in the past, the critical point at which LSRD power needs to be replaced moves even farther into the future.

Open Market Value of LSRD Power

As a beginning point, it is possible to make a very simple and very precise measure of the value of the power produced by the LSRD. On the generation side, the United States Army Corp of Engineers (ACOE) operates the dams and publishes hour-by-hour generation data dating back to the construction of the projects.

The LSRD generation for 2009 through 2014 is presented in Chart 3 immediately below. Like most hydro projects LSRD generation exhibits extreme seasonal variation, with spring runoff peaks in the vicinity of 60,000 megawatt hours (Mwh), roughly three times as high as the 20,000 Mwh per day generation that is normal in the summer, fall and winter.

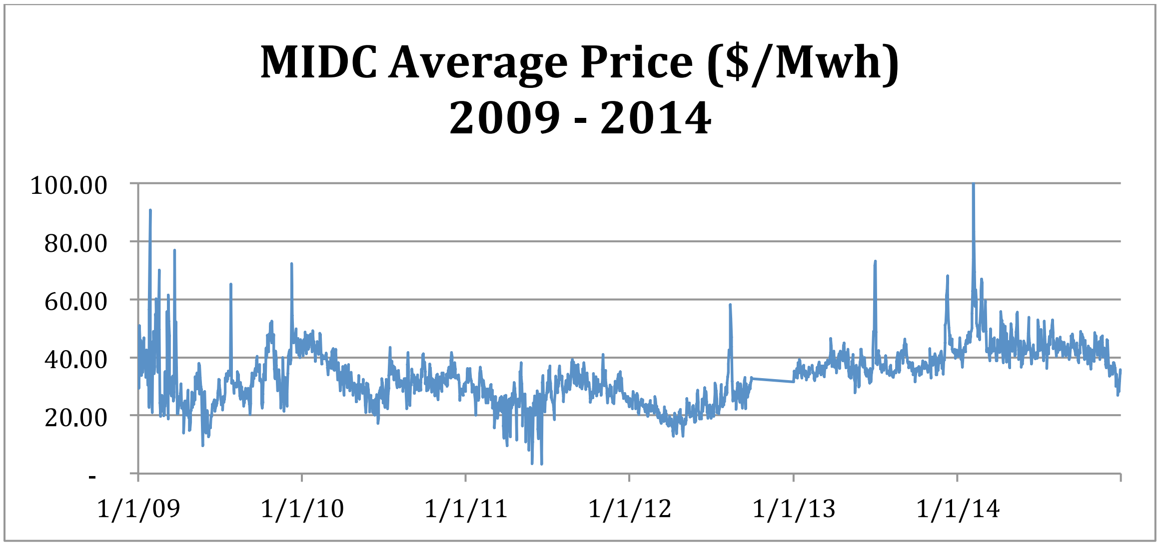
Chart 3



On the pricing side, the closest open market trading hub for the LSRD is the Mid Columbia (MIDC) trading hub. MIDC is not publicly reported. However, the California Independent System Operation (CAISO) publishes hour-by-hour price data for the California-Oregon Border (COB) trading hub (Listed as NP15 in CAISO data). NP15 is a mirror of the unpublished MIDC trades. See Appendix I for more detail on NP15v vs. MIDC prices.

Chart 4, below, presents the MIDC, day-ahead[5] prices for electricity for the time period matching LSRD generation in Chart 3. There is a corresponding seasonality to price swings, but the magnitude is less severe than the swings in generation by the LSRD, at least in part because market prices deal with a multitude of generating resources in addition to the LSRD. Where spring generation is roughly three times that of generation the rest of the year, late spring open market prices typically only fall to about half of the annual peak prices.

Chart 4



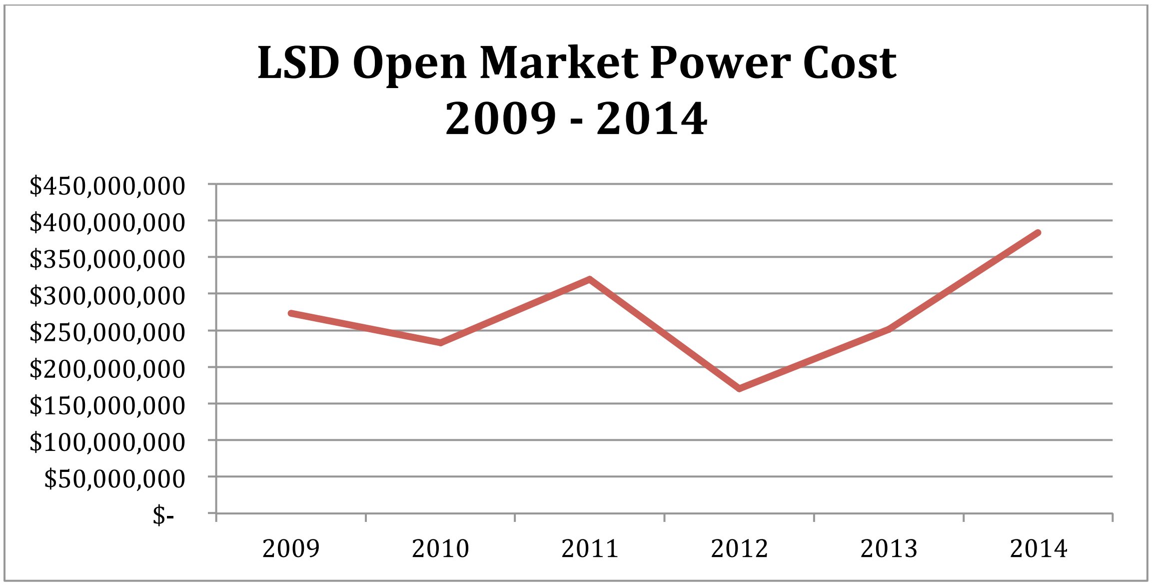
With the table of LSRD generation, at the hourly level from 2009 to present, and the table of MIDC Day Ahead firm prices, at the hourly level from 2009 to present, it is a simple mater to multiply one set of numbers by the other to arrive at what it would have cost to procure the exact value of LSRD generation, hour by hour, year by year. The result of that calculation is presented in Table 3 and Chart 5 below.

[5] CAISO also publishes real time, spot, and prices for all the trading hubs. RME used day-ahead pricing. Day-ahead prices are for firm power. As such the prices are a little higher and less volatile than spot prices.

Table 3

Year	Total Cost
2009	$273,702,134
2010	$233,266,843
2011	$319,619,726
2012	$170,313,879
2013	$251,319,878
2014	$383,592,786
Avg. 2009 - 2014	**$271,969,207**
Median 2009 - 2014	**$262,511,006**

Chart 5



Based on actual generation numbers and actual pricing numbers for 2009 through 2014[6], the most it would have cost to replace LSRD energy would have been $383 million in 2014. At the other extreme, in 2012 it would have only cost $170 million to replace the energy. The average cost of replacement would have been $272 million. The median replacement cost was a bit lower at $263 million.

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6 A quick glance at Chart 5 might lead a person to believe that open market prices are headed for the roof. Please see Appendix II for more detail on NP15 price history and why fears of higher prices are unfounded.

There are arguments for using numbers both higher and lower than the ones presented in this section. I will deal with those arguments in following sections. The more interesting point for the moment is that the numbers presented in this section are exactly what it would have cost to procure on the open market the precise amount of power that the LSRD produced at the precise moment when the power was being produced. While the ACOE and others have presented forecasts of power costs, as RME will do in the following sections, the numbers presented above are actual numbers. To that end they have a degree of validity hard to arrive at with price forecasts.

Median Water Power Planning

Procuring as much as 60,000 Mwh of energy per day on an occasional basis, or 20,000 Mwh of energy per day on a regular basis, on the open market would might strain the current MIDC market and force prices higher. To that end, this valuation could be viewed as being on the low side.

Countering the preceding argument, it must be observed that the only reason the LSRD produce and sell 60,000 Mwh of energy each spring is because the marginal cost of doing so is zero. This is power that would not be produced if the marginal cost were anything above zero. This is surplus production that tends to drive open market prices down. It is power that already has backup resources in place. It is power that does not need to be replaced. The result is that adding in the market value of this surplus power produced in the spring tends to overvalue cost of replacing LSRD power.

Every power source has an Achilles heel. Wind turbines fail in calm conditions and solar fails at night. Hydropower fails in drought years. Any plans to sell hydropower in excess of that which can be produced by minimum stream flows must necessarily be backed up by one or more other resources, typically a gas or coal plant. In practice minimum stream flow planning is a bit severe so most utilities use some version of median stream flow planning. For the LSRD the median power produced from 2009 through 2014 is 19,067 Mwh per day, or 795 aMW.

Looking at the same data tables used to produce the results in Table 1, it is possible to extract both median levels of power generation at the LSRD, by hour, for 2009 – 2015. It is also possible to extract the median price of power at MIDC, by hour, for 2009 – 2014. The result is presented in Table 4 on the following page.

Procuring median water levels of LSRD generation at open market pricing based on actual MIDC prices would cost $239 million.

Table 4, Median Value of LSRD Power.

Hour	Med Price x Med Gen
1:00 AM	$14,214
2:00 AM	$12,223
3:00 AM	$10,762
4:00 AM	$10,378
5:00 AM	$11,481
6:00 AM	$15,427
7:00 AM	$22,818
8:00 AM	$28,466
9:00 AM	$29,845
10:00 AM	$31,094
11:00 AM	$32,169
12:00 PM	$32,421
1:00 PM	$32,150
2:00 PM	$32,229
3:00 PM	$32,842
4:00 PM	$33,860
5:00 PM	$36,499
6:00 PM	$40,242
7:00 PM	$41,403
8:00 PM	$40,945
9:00 PM	$39,438
10:00 PM	$32,861
11:00 PM	$25,013
12:00 AM	$17,149
Total Median Day	**$655,930**
Total Median Year	**$239,414,453**

Replacement Power Via Solar and the Open Market

The previous section dealt with the lack of need to replace surplus power production in excess of median waterpower production. However, especially in the absence of the surplus spring runoff production, it may be unreasonable to suddenly go to the open market to replace LSRD median generation of 19,067 Mwh per day on a continuing basis without it having an upward impact on prices.

It is worth emphasizing the phrase "may have an upward impact on prices." As this is being written various PUC's across the region are being lobbied to stop the deluge of PURPA wind and solar plants that are putting them into a surplus power position. The surplus power portion is, of course, finding its way onto the open market where it is driving prices down. The point being, since the region is going further into surplus as more and more wind and solar projects come in under the $35.10 Mwh PURPA hurdle, it seems just as likely that picking up 19,067 Mwh per day on a continuing basis won't be either difficult of expensive.[7] Further, the energy market is like any market, it reacts. If producers see higher equilibrium prices, and believe they can profitably supply the demand, they will build projects, supply additional energy, and prices will come back down. Still, for the purpose of this exercise, the next few paragraphs explore the cost of sourcing power from a combination of solar and open market. My reason for choosing solar is that solar is a great fit for the northwest. It is "on" when demand is highest, namely the summer irrigation and air conditioning peaks. Admittedly, it gets dark at night, but that is when there is always abundant power available on the open market.

Table 3, on the following page, presents a case for providing median water amounts of LSRD power via a combination of solar and the open market. The price of solar is based on the Avista and Idaho power avoided cost rates of $35.10 per Mwh. To account for the cloudy days and different sun angles over the course of the year I applied a capacity factor of .85. This increases the cost of solar to $41.29 per Mwh. For the hours 8 PM till 8 AM the assumption is that power will be sourced from MIDC.

This option is a very feasible option. The avoided cost rates are rates that solar producers are routinely seeking from northwest investor owned utilities as this is being written. The off-peak power is readily available at MIDC / NP15 at

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[7] The Idaho PUC recently granted Idaho Power a rate increase as part of their annual power cost adjustment (PCA). As a means of offsetting some of their production costs, IPC sells surplus power on the open market. One of the factors cited as the need for Idaho Power to increase costs was, "**<u>Because of lower prices on the wholesale energy market</u>**, Idaho Power is forecasting only $39 million in sales, down from the $51.7 million included in base rates." IPUC Press Release, 5/28/2015. (Emphasis RME)

comparable prices. Finally, significantly, the total annual cost to replace median water LSRD power via the method presented here, at $260 million, is both very firm and very close to the cost displayed in the open market case presented in Table 1 above.

Table 5, Solar Replacement Power

Hour	Median Gen	Median MIDC	Avista-Idaho Power ACR			Solar + Open Market Value
1:00 AM	506.06	$28				$14,214
2:00 AM	475.9	$26				$12,223
3:00 AM	463.12	$23				$10,762
4:00 AM	463.32	$22				$10,378
5:00 AM	483.5	$24				$11,481
6:00 AM	559.42	$28				$15,427
7:00 AM	764.57	$30				$22,818
8:00 AM	889.22		$35.10	0.85	$41.29	$36,720
9:00 AM	925.47		$35.10	0.85	$41.29	$38,216
10:00 AM	937.46		$35.10	0.85	$41.29	$38,712
11:00 AM	935.05		$35.10	0.85	$41.29	$38,612
12:00 PM	923.26		$35.10	0.85	$41.29	$38,125
1:00 PM	913.51		$35.10	0.85	$41.29	$37,723
2:00 PM	903.43		$35.10	0.85	$41.29	$37,306
3:00 PM	898.56		$35.10	0.85	$41.29	$37,105
4:00 PM	907.83		$35.10	0.85	$41.29	$37,488
5:00 PM	928.17		$35.10	0.85	$41.29	$38,328
6:00 PM	968.88		$35.10	0.85	$41.29	$40,009
7:00 PM	991.7		$35.10	0.85	$41.29	$40,951
8:00 PM	1000.9	$41				$40,945
9:00 PM	985.15	$40				$39,438
10:00 PM	913.89	$36				$32,861
11:00 PM	750.91	$33				$25,013
12:00 AM	577.91	$30				$17,149
Sum of Median Hours	**19,067**					**$712,006**
Total Year	**6,959,524**					**$259,882,009**

Footnote to solar power cost. There is an element to solar power, at least photovoltaic-based systems, that is rather unique to power production. Just about every other power production system has a lot of moving parts that have to be repaired and replaced on a continual basis. PVs, on the other hand just sit there. They do degrade a little over time but not nearly to the extent that turbines and conventional generators do. The point is that the prices shown here are primarily for the first 20 years of a project. After that the capital cost associated with a PV solar plant will be retired and the cost of PV power may drop into the teens. To the extent these prices and values are going to be used for 100 year planning, this estimate is very, very conservative.

Summary

In the preceding pages RME presented three alternative scenarios for replacing LSRD power generation. The first, Open Market purchase of LSRD power resulted in a median annual cost of $263 million. The second, open market purchase of median water levels of LSRD generation resulted in an annual cost of $239 million. The third, using photo voltaic power to cover the bulk of power, with open market purchase covering night time power, resulted in an annual cost of $260 million.

Jim Waddell, retired ACOE engineer, has calculated that it will cost $312.9 million annually[8] to maintain the dams, 90 percent of which, $281.6 million, is allocated for power generation.[9] Compared to Waddell's calculations, all three of the scenarios developed by RME are lower cost options than maintaining the dams. Open Market purchases of the power would save ratepayers nearly $19 million per year, or six cents off of each monthly bill. If replacement power were limited to median water purchases, the savings would be $42 million per year, about a thirteen-cent reduction in a typical residential monthly bill. If PV farms were utilized to replace the power, with open market purchases of nighttime power, the annual savings would be about $22 million, six cents per month cheaper for a typical residential consumer.

Table 6, Cost of Maintaining the LSRD vs. Replacement Power

Total Annual Cost to Keep LSRD*	Open Market Purchases 2009-2014		Median Water Open Market Purchase		Combination PV Gen and Open Market Purchase	
	Cost (Median)	Incremental Cost	Median Cost	Incremental Cost	Median Cost	Incremental Cost
$281,600	$262,511	-$19,099	$239,414	-$42,196	$259,882	-$21,728
Monthly Difference In Residential Bills	-$0.06		-$0.13		-$0.06	

8 The Costs of Keeping the Four Lower Snake River Dams: A Reevaluation of the Lower Snake River Feasibility Report, Jim Waddell and Linwood Laughy, 2015, pp. 10.

9 Ibid.

Appendix

I Mid-C / NP15 Price Differential

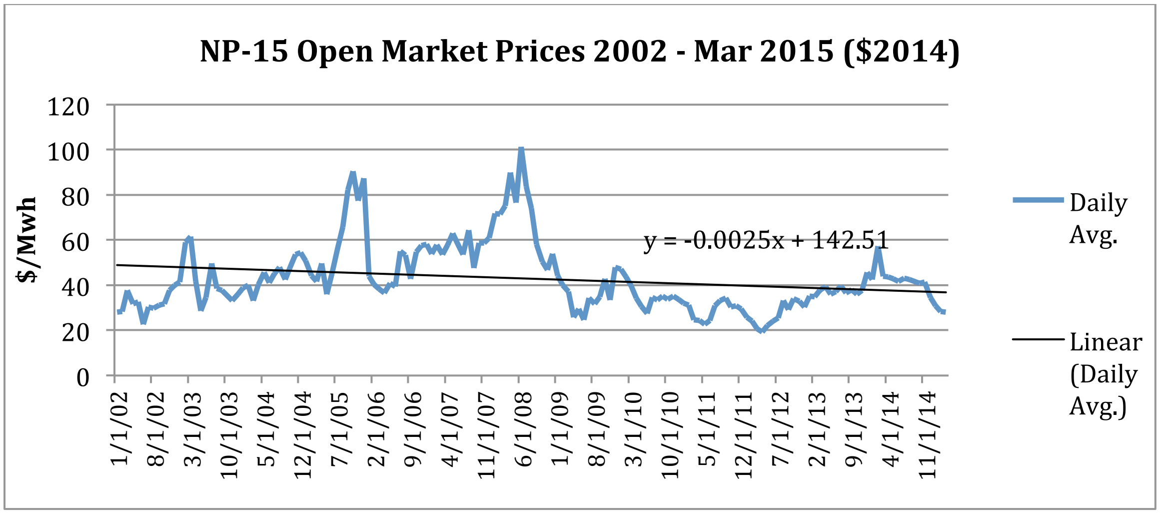
Annual Average Day Ahead On Peak Prices ($/Mwh) [10]

	2006	2007	2008	2009	2010	5-Year Avg.
Mid-Columbia (Mid-C)	$50.18	$56.57	$65.00	$35.66	$35.90	$48.67
California-Oregon Border (COB)	$55.58	$62.14	$73.86	$38.02	$38.84	$53.70
NP15	$61.08	$66.59	$80.14	$39.29	$40.08	$57.45
Difference, NP15 Minus Mid-C	**$10.90**	**$10.02**	**$15.14**	**$3.63**	**$4.18**	**$8.78**

NP15, COB, and Mid-C are, in order of magnitude, the three main open market electricity trading hubs in the Pacific Northwest. NP15 represents the Northern California market, COB represents the California Oregon Border, and Mid-C is the Mid Columbia Basin. Mid-C is the most relevant market for the LSRD but it is not publicly reported. The fact that NP15 is publicly reported on the California ISO Open Access Same-time Information System (CAISO/OASIS) site, and that it moves consistently with and is slightly higher than Mid-C, makes it ideal for analyses such as this. In the tables in the body of this exercise, MIDC is assumed to be NP15 minus $2.50 per Mwh. This has the effect of making MIDC prices appear about $5.28 per Mwh higher than the 2006 – 2010 average calculated by the Federal Energy Regulatory Commission. It also means the cost savings associated with open market purchase presented in the body of this paper are understated.

[10] Federal Energy Regulatory Commission • Market Oversight @ FERC.gov, NW, CA, pp. 5, 2011.

II NP15 Day Ahead Open Market Energy Prices, 2002 – Current



Open market prices are somewhat volatile. That said, extreme high prices are invariably followed by downward corrections. The trend from 2002 through 2008 was clearly upward. The correction in 2009 reversed the previous trend. 2014 prices were higher than the two previous years, but 2015 prices have returned to near record lows. The long-term trend in open market prices continues to be downward.