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IDAHO PUBLIC UTILITIES COMMISSION

October 5, 2015

Idaho Public Utilities Commission
472 W Washington St
Boise, ID 83702

Re: Comments on Idaho Power's 2015 Integrated Resources Plan, Docket # IPC-E-15-19

Dear Commissioners,

The Sierra Club thanks you for the time you will spend considering these comments regarding Idaho Power's 2015 Integrated Resource Plan. Sierra Club is America's oldest and largest grassroots environmental organization, with 1.4 million members and supporters, including over 2,000 members in Idaho. We hope that you will find that our comments suggest a positive solution for some of the difficulties and opportunities that new clean energy alternatives present.

We recognize and applaud several substantive improvements Idaho Power has made in this 2015 Integrated Resource Plan (IRP). Nonetheless, we believe that changes are needed in the way transmission and distribution (T&D) system costs are included in the IRP analyses. Our expectation is that distributed solar generation and enhanced information system enabled demand management opportunities can facilitate reductions in T&D expenditures. Updating the IRP analysis to include T&D costs can reveal even more cost-effective resource alternatives than the IRP currently considers.

WE APPLAUD MULTIPLE IMPROVEMENTS IN THIS IRP

In our estimation, Idaho Power's 2015 IRP is the latest step along a path of continuous improvement in the Company's recent resource planning activities. The 2015 iteration is the best IRP yet.

We especially appreciate the personal participation of the Company President, Darrel Anderson, in setting the goal of a broad and open IRPAC discussion during the development of this IRP. Kudos also to Phil DeVol and his team for facilitating dialogue and including feedback and ideas from various stakeholders into this planning process.

While the 2013 IRP attempted to integrate the results of a contemporaneous coal study, the 2015 IRP did a much better job of both integrating the studies and considering a broader range of coal unit retirement alternatives.

Additionally, compared to previous IRPs, this iteration used vastly improved estimates for the capacity value and cost of solar PV.[3]

We also think the feeder line voltage support and thermal energy storage pilot projects are small but valuable steps into a much-needed closer examination of options at the distribution system level.

While we greatly appreciate the aforementioned positives, we believe it is necessary to improve how distributed solar generation is valued.

REDUCED COST OF SOLAR PV NECESITATES NEW ANALYSIS OF COSTS AND POTENTIAL SAVINGS AT THE TRANSMISSION AND DISTRIBUTION LEVEL

Our concerns related to distribution system costs can be summarized as follows:

- It costs a lot to transport electrons from where they are generated to where they are used.
- In the past those costs weren't controllable, but now newly cost-effective distributed solar generation and demand management may be able to eliminate some T&D costs.
- As it's used today, the Aurora cost model does not identify those potential T&D cost savings.
- We believe the IRP cost analysis process needs to be modified so that it reflects the benefits of distributed solar generation and demand management more fairly.

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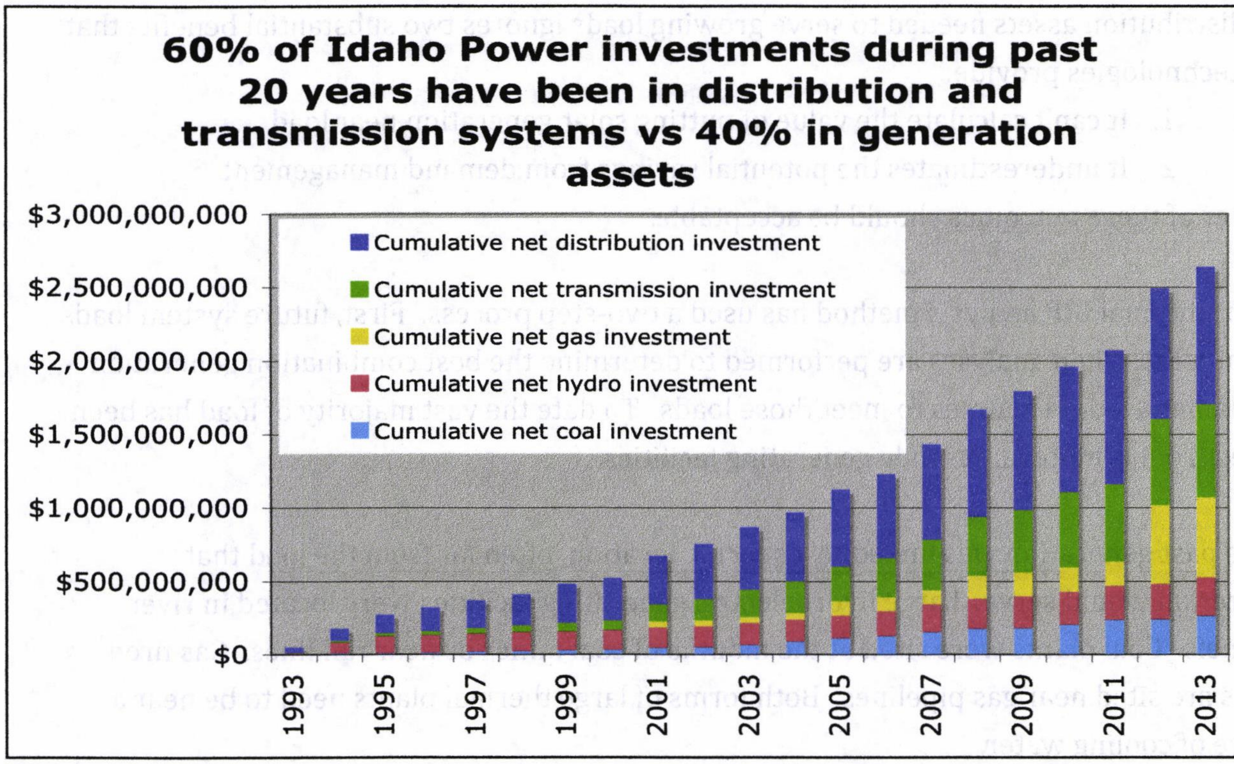
[3] See Idaho Power Company Integrated Resource Plan 2015, figures 7.7 & 7.8, p 90 & 91 respectively

GENERATION IS LESS THAN HALF OF THE COST OF GETTING POWER TO THE USER

IRPs look out twenty year in to the future. To get a sense of the magnitude of the potential T&D savings, let's look back twenty years.

Over the last two decades the majority of Idaho Power capital expenditures have been on transmission and distribution systems, not on generation assets. Of course we expect that future to be different from the past. But the figure below shows that during the decades between 1993 and 2013, Idaho Power spent 50% more on maintaining and expanding their T&D assets than they did building out all their natural gas, coal and hydro generation combined. We believe that distributed solar generation and peak load control can potentially eliminate some of the transmission and distribution system costs that traditional large-scale generation couldn't do without.



[4]

A recent Idaho Power publication shows the problem of ignoring opportunities to control T&D expenditures even more starkly. In the July 2015 issue of CONNECTIONS Magazine,

[4] Source: Idaho Power Company FERC Form 1 reports, years 1993 through 2013

under the heading "We're all in this (Grid) Together" the Company states:

> "Only part of your bill goes to pay Idaho Power for the electricity you use. The majority -- about 70% -- actually pays for building, operating and maintaining the grid that reliably delivers your power"

The current IRP analysis method (the Aurora model) focuses on costs to generate energy and wheel it into the Idaho Power service territory. It ignores the cost of getting that energy transported within the service territory to where it is ultimately used. Updating the cost analysis method Idaho Power uses to value distribution within its service territory is essential to appropriately value distributed generation and load management alternatives.

NEW TECHNOLOGY WARRANTS DISTRIBUTION SYSTEM LEVEL REVIEW

An IRP analysis that overlooks the potential to control future expenditures for transmission and distribution assets needed to serve growing loads ignores two substantial benefits that new technologies provide:

1. It can't calculate the value of putting solar generation near load
2. It underestimates the potential savings from demand management.

Neither of these outcomes should be acceptable.

The traditional IRP analysis method has used a two-step process. First, future system loads are forecast. Then analyses are performed to determine the best combination generation and demand side resources to meet those loads. To date the vast majority of load has been served from remote large-scale generating facilities.

In the past generation was linked to a specific location, often far from the load that generation would serve. Large hydroelectric generating facilities were located in river channels. Coal plants were sited at the mouths of coal mines or near rail lines. Gas fired plants are sited near gas pipelines. Both forms of large thermal plants need to be near a source of cooling water.

Even the small PURPA renewable generation facilities the Company has experience with were site constrained (e.g. small hydro at canal drops, wind in energetic locations, combined heat and power (CHP) at an industrial facility, and digesters near CAFOs).

We acknowledge that costs for adding new transmission lines have been analyzed for years. But these new transmission alternatives have been valued primarily as a method to access other remote generation sources and/or markets.

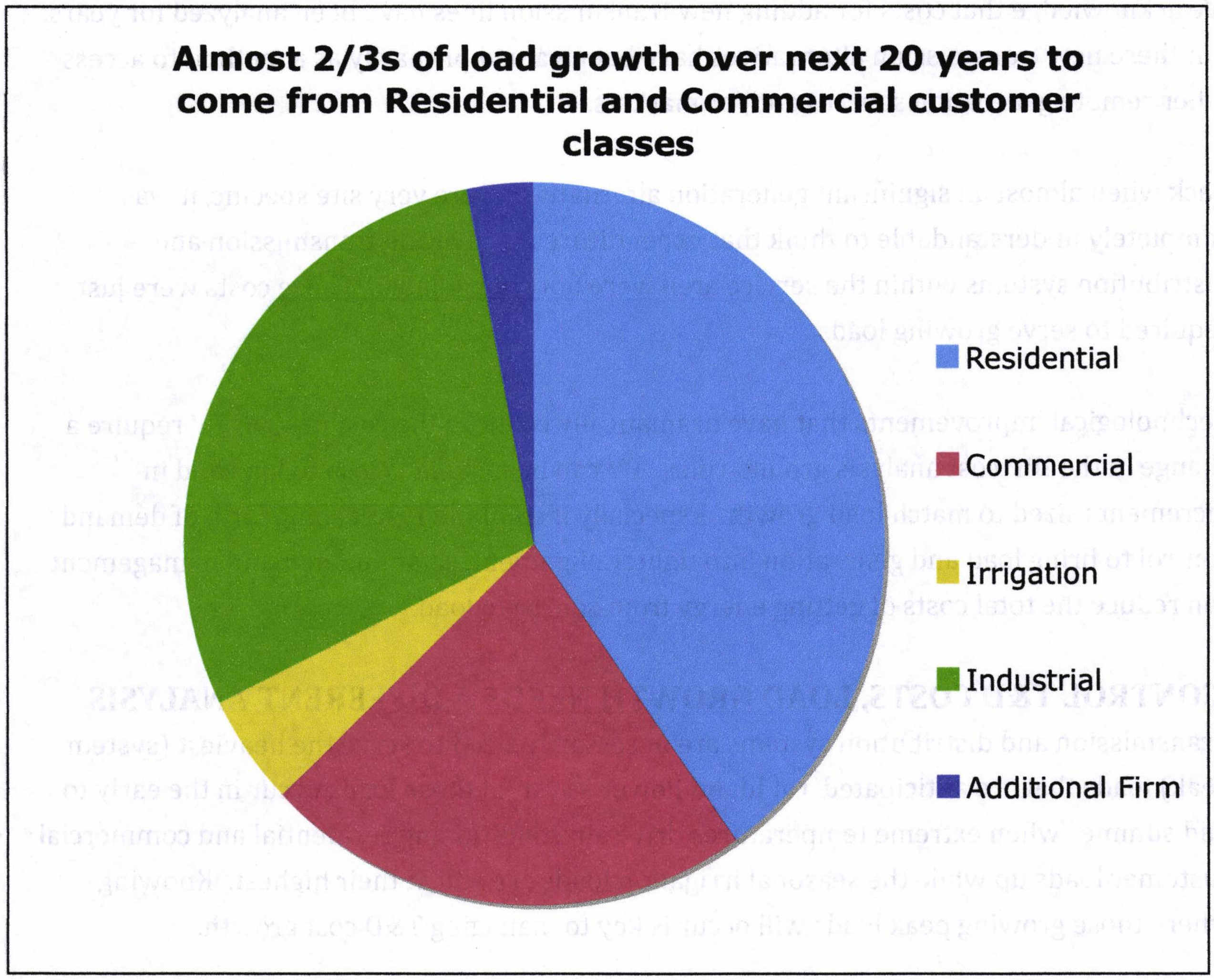
Back when almost all significant generation alternatives were very site specific, it was completely understandable to think that expenditures to upgrade transmission and distribution systems within the service area were not controllable. Those costs were just required to serve growing loads.

Technological improvements that have dramatically reduced the cost of solar PV require a change in the IRP cost analysis ground rules. PV can be installed close to load and in increments sized to match load growth. Especially if combined with some form of demand control to bring load and generation into tighter alignment, solar and demand management can reduce the total costs of getting energy from source to load.

TO CONTROL T&D COSTS, LOAD GROWTH NEEDS A DIFFERENT ANALYSIS

Transmission and distribution systems are necessarily sized to serve the heaviest (system peak) loads that are anticipated. On Idaho Power's system those loads occur in the early to mid summer when extreme temperatures drive air-conditioning residential and commercial customer loads up while the seasonal irrigation loads are still at their highest. Knowing where those growing peak loads will occur is key to managing T&D cost growth.

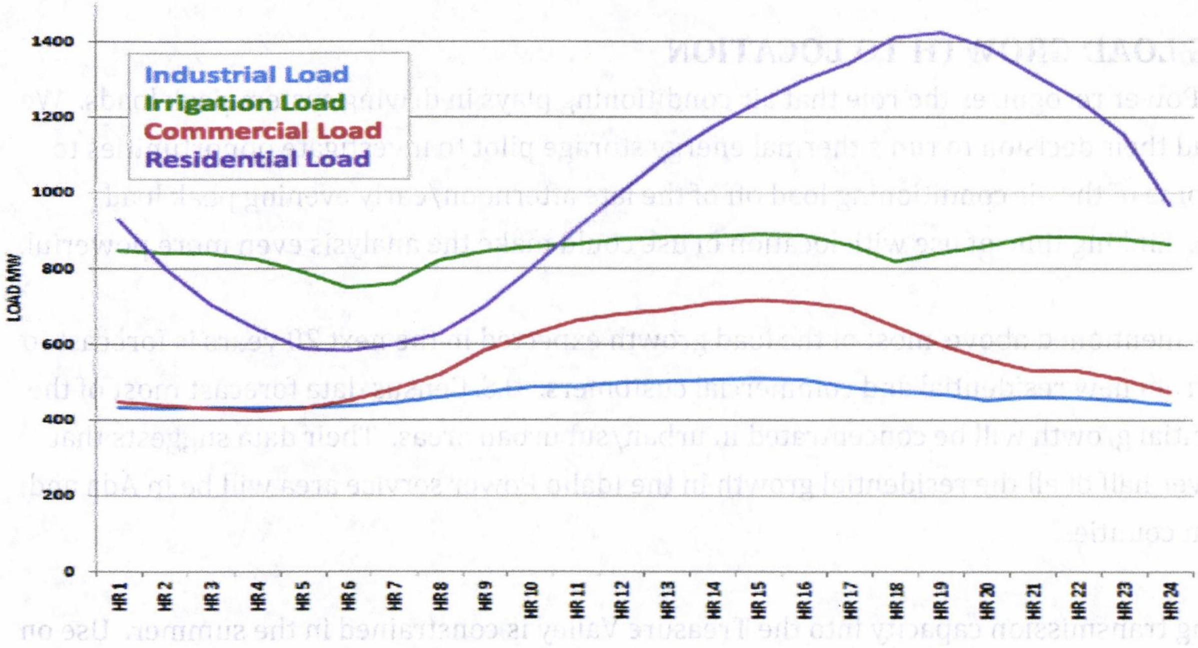
Within the IRP, load is projected by customer classes. The 70^{th} percentile energy sales values used for planning purposes projects a 3,750,000MWh increase in annual billed sales. The majority of that increase will come from growth in residential and commercial load.



[5]

Not only will residential and commercial customer loads account for most of the growth expected during the next 20 years, those two classes show the highest inter-day load rises, which, in turn, drive peak loads.

[5] Source: Integrated Resource Plan 2015 Appendix C, 70th percentile Load Forecast Annual Summary, pages 27 & 28



[6]

The figure above shows how different customer class loads varied over the twenty-four hour period (July 2,2013) when Idaho Power experienced what was at that time its all time system peak load. Note that while both the Industrial and Irrigation customer loads were relatively constant over the twenty-four hour period, residential customer load rose more than 140% during the course of the day (from a low of about 580MWs @ 5am to about 1,420MWs @ 7pm). Commercial showed a smaller, but still substantial 65% rise over the day (from about 440MWs @ 5am to about 720MWs @ 3pm).

During the next 20 years the majority of the load growth is expected to come from the two customer classes that use the most air conditioning and exhibit the largest diurnal load rise during times of system peak loads. As has been the case for the past decade, peak loads are projected in the 2015 IRP to continue to grow faster than average load. Since T&D system size grows to meet peak load, T&D requirements will likely exceed generation growth between now and 2034. An analysis method that fails to evaluate opportunities to control T&D cost growth will become even more problematic over time.

[6] Source: August 7, 2014 IRPAC Advisory Council Meeting Presentation, p 19

LINKING LOAD GROWTH TO LOCATION

Idaho Power recognizes the role that air conditioning plays in driving system peak loads. We applaud their decision to run a thermal energy storage pilot to investigate opportunities to shift some of the air conditioning load off of the late afternoon/early evening peak load period. Linking time of use with location of use could make the analysis even more powerful.

As was mentioned above, most of the load growth expected in the next 20 years is forecast to come from new residential and commercial customers. U.S. Census data forecast most of the residential growth will be concentrated in urban/suburban areas. Their data suggests that well over half of all the residential growth in the Idaho Power service area will be in Ada and Canyon counties.

Existing transmission capacity into the Treasure Valley is constrained in the summer. Use on the Idaho-Northwest west-to-east path is limited in the summer by BPA and IPCo loads. The Brownlee East west-to-east path is similarly constrained in the summer by flows from the Hells Canyon Complex as well as other BPA and IPCo on Idaho-Northwest path. The Idaho-Montana north-to-south path is summer constrained by BPA, PAC and IPCo loads and the Borah West east-to-west path is also full in the summer.[7]

In preparing their load forecasts the Company uses economic projections scaled at the county and metropolitan statistical area level (MSA).[8] Since they are basing their forecasts on data collected at the MSA and county level, it should be relatively easy to break out load growth by region.

Ada and Canyon counties have excellent summer solar resources. With much of the future load growth expected in the Treasure Valley, it should be possible to compare the cost of building new solar generation at keys locations within the Valley with the potential saving from avoiding expenditures on new transmission and distribution system assets to serve that growing load with the total cost of power generated remotely.

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[7] Source: Idaho Power Company Integrated Resource Plan 2015, p 64 & 65

[8] Source: Idaho Power Company Integrated Resource Plan 2015, p 73

CURRENT ANALYSIS VASTLY UNDER-ESTIMATES COST TO SERVE PEAK LOADS

In the third chapter of the 2015 IRP the Company provides an indication of how expensive it is just to provide the generation to serve each of the 9,800 new residential customers they expect to gain per year over the next twenty years.

> "...each new residential customer requires over $1,700 of capital investment for 1.5kW of base load generation, plus an additional $4,400 for the 5 to 6 kW of peak-hour capacity...(not including)...(o)ther capital expenditures for transmission, distribution, customer service, and other administrative costs"[9]

The current analysis also fails to consider the extensive costs in the T&D system (which is sized to serve system peaks that only occur every few years) when valuing demand management opportunities. In tables and text the Company values energy efficiency (and presumably demand management) programs based on the

> "benefit(s) of the (efficiency and demand side management) program is avoided energy, which is calculated by valuing the energy savings against the avoided generation costs of Idaho Power's existing marginal resource."[10]

Reducing the size of system peak loads saves more than just avoided operation of existing generation. Growing Peak loads will require more transmission, distribution and peak hour generating capacity. Solar generation installed at beneficial locations near the areas of future load growth, combined with demand management programs (like the TES pilot), can reduce future expenditures on generation, transmission and distribution assets.

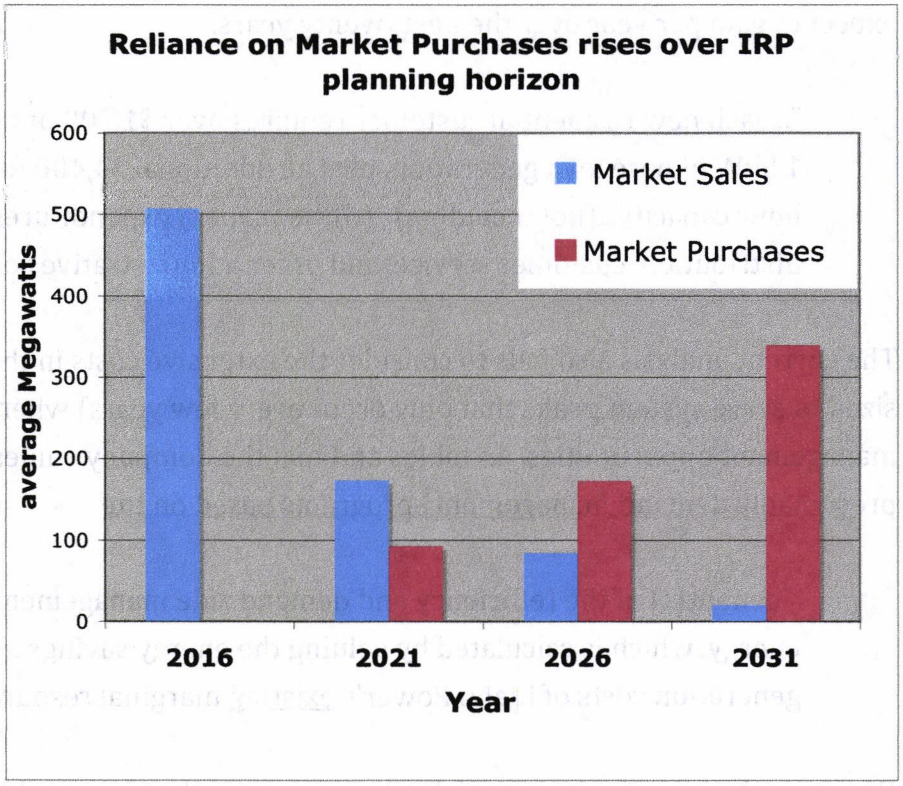
[9] Source: Idaho Power Company Integrated Resource Plan 2015, p 25

[10] Source: Idaho Power Company Integrated Resource Plan 2015, p 45

POSSIBLE IMPLICATIONS: LOWERING BOTH COST AND RISK

The 2015 IRP is written and we are not trying to change its contents. The examples shown below are just meant to be illustrative.

The preferred portfolio shifts IPCo from a net seller into net purchaser of market energy. The chart below shows how over the course of the 20-year IRP horizon Idaho Power shifts from a net seller in the market place in 2016 and 2021 to a net purchaser in 2026 and 2031. This rising reliance on market purchases presents multiple potential problems that would not arise had distributed solar generation been appropriately valued.



[11]

At the highest level "buying" off market, rather than "making" utility owned generation is inconsistent with the statement made in Chapter 10 of the IRP that:

> "in the long run Idaho Power believes asset ownership results in lower costs to customers"[12]

At a less theoretical level making more of the energy needed in the Idaho Power service area rather than buying it off the market would reduce customer exposure to both risks of both

[11] Source: Idaho Power Company Integrated Resource Plan 2015 – Appendix C, p 27 & 28

[12] Source: Idaho Power Company Integrated Resource Plan 2015, p 143

price level and supply adequacy.

In the chapter on modeling analysis, the Company notes that in a recent study the Northwest Resource Adequacy Advisory Committee (RAAC) projects a Loss of Load Probability (LOLP) in the Mid-Columbia market area that rises to an unacceptable level of 8% in 2021 due to closure of coal capacity at Boardman and Centralia (unless 1,150 MWs of dispatchable generation is added). January, February and to a lesser extent August are most critical months for these reliability problems in the Pacific NW region.[13]

The question that occurs to us is if capacity NW wide is critical in August, why do we believe that increased access to the Mid-C market will serve as a reliable capacity resource for Idaho Power?

Buying off the market rather than using fuel-risk free solar generation effectively shifts additional price risk on to Idaho Power's customers. The benefits of shielding customers from year to year price adjustments were shown in the risk assessment of year-to-year price variability in Figure 9.2.[14] That analysis clearly shows that Idaho Power customers would be much better protected from year to year price adjustments if the Company were to build out more solar (as modeled in Portfolio 3) rather than rely so much on market purchases as in the preferred Portfolio 6b.

Part of the explanation for why Portfolio 6b was preferred over the more solar reliant Portfolio 3 was due to Portfolio 3 being evaluated as about $26 million more expensive over the 20-year period[15]. Using the tipping point analysis shown in Figure 9.3[16] shows that if solar PV capital costs were approximately 15% lower the total portfolio costs would be reduced by about $25 million.

In other words, if solar capital costs were overstated by 15% in the 2015 IRP, that overstatement would account for the entire cost difference between Portfolio 3 and the Company's preferred Portfolio 6b.

[13] Source: Idaho Power Company Integrated Resource Plan 2015, p 129

[14] Source: Idaho Power Company Integrated Resource Plan 2015, p 124

[15] Source: Idaho Power Company Integrated Resource Plan 2015, p 117

[16] Source: Idaho Power Company Integrated Resource Plan 2015, p 125

Ironically, as explained below, a 15% overstatement of solar PV capital cost is almost the precise amount by which potentially distributed solar was overcharged for "transmission capital".

Both reciprocating engine powered generators and solar PV can be installed in quantities that allow interconnection to the distribution system. But the way they were charged for T&D interconnection in the 2015 IRP does not reflect this equivalence.

Table 6.3 in the IRP shows each utility scale unit of 10MW worth of PV solar is charged with needing a new 138kv line and substation. The same table shows a larger generator (18MW of reciprocating engine powered generation) requires no new transmission[17]. Checking the IRP Technical Report - Appendix C we find that in estimating the cost of 18MW of reciprocating engine powered generators, they are assessed a transmission capital cost at $75/kW. The comparable transmission capital cost assessment for 10MWs of utility scale solar PV is $305/kW[18] or an additional $230/kW. As the "plant" capital costs of solar PV installed after 2017 was estimated at $1,250/kW, the extra $230/kW interconnection assessment represents a capital cost overstatement of 14.8%,[19] or effectively a 15% overstatement of solar PV capital costs.

If assessed appropriately for estimated interconnection costs, solar is already as cost effective and lower risk than the preferred portfolio. If the IRP analysis were updated to recognize the value of distributed generation's (both PV solar and natural gas fired reciprocating generators) ability to defer T&D expenditures, solar would likely be viewed much more favorably. The 2017 IRP needs to eliminate these valuation problems.

Request

In addressing the opening IRPAC meeting Company President Darrel Anderson stated that one of the Company's goals is to provide power to its customers at fair prices and to do so in a way that would promote regional growth.

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[17] Source: Idaho Power Company Integrated Resource Plan 2015, p 72

[18] Source: Idaho Power Company Integrated Resource Plan 2015 - Appendix C, p 85

[19] $230 / ($1,250 + $305) = 14.8%

We take him at his word and ask that you direct the Company to improve the 2017 IRP in the following fashion.

1. First, expand the scope of future IRP alternatives cost analyses to consider all relevant T&D expenditures, not just generation costs.
2. Second, make a concerted effort to insure that in the 2017 IRP solar PV costs are more fairly estimated.

If those two changes were implemented, we believe that the Company will find that investing in solar generation distributed close to the growing Treasure Valley load is superior to other alternatives. A shift in Company capital expenditures away from wires and transformers and redirecting those funds to capital intensive but free fuel solar generation could help meet both of Mr. Anderson's stated goals.

Zack Waterman

Zack Waterman

Director
Idaho Sierra Club

cc: Mike Heckler