ABSAROKA ENERGY LLC

May 29, 2018

Comments of GB Energy Park, LLC Energy
Docket No. UE-180271 – Puget Sound Energy 2018 Request For Proposal for All Generation Resources

These comments are offered by GB Energy Park, LLC (GBEP), developer of the Gordon Butte Pumped Storage Hydro Project (Gordon Butte PSH or Project), in response to Puget Sound Energy's (PSE) Draft 2017 Resource Request for Proposals. GBEP is a single-purpose subsidiary of Montana-based Absaroka Energy Development Group, LLC (Absaroka).

Introduction

GBEP participated in the meetings of the PSE Advisory Group (IRPAG) during the development of the 2017 Integrated Resource Plan (2017 IRP). During this time, GBEP was informed on PSE's energy supply situation, its planning processes, and filed written comments on the 2017 IRP, following its release on January 16, 2018. These comments may be found on the Washington Utilities and Transportation Commission's (UTC) website under Docket No. UE-160918.[1]

GBEP is developing the Gordon Butte Pumped Storage Hydro Project, a 400 MW, closed-loop pumped storage hydro facility with 3,400 MWh of storage capability to be interconnected to the Colstrip 500 kV transmission lines near Martinsdale, Montana. Gordon Butte will employ the latest ternary pumped storage hydro (PSH) technology to provide fast-ramping flexible capacity ideally suited for integrating intermittent renewable resources into the Pacific Northwest transmission grid. Gordon Butte, coupled with Montana's robust wind resources, provides a reliable, cost-competitive, and carbon-free solution for replacing the capacity and energy deficit from the retirement of Colstrip units 1&2 (no later than 2022), and subsequent retirements of Colstrip units 3&4, as well as other needs the utility may have in the future (see E3 study provided as Attachment C).

On December 14, 2016, the Federal Energy Regulatory Commission (FERC) issued the Original License for Gordon Butte (FERC Docket No. P-13642) to construct and operate the Project for a 50-year period. Gordon Butte has completed its licensing and

[1] https://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/resourcePlansByCompany.aspx

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development activities and is construction-ready. Additional information on the Project can be found at: http://gordonbuttepumpedstorage.com/.

Proper evaluation of storage resources

The Washington Utilities and Transportation Commission (UTC) issued a white paper offering guidance to PSE on the evaluation of energy storage resources in May of 2015, *Modeling Energy Storage: Challenges and Opportunities for Washington Utilities.* GBEP is in broad agreement with the analysis contained within this document. Among them:

- Absent clear price market signals, determining the true value of the services that energy storage provides can be a challenge.
- Continued increase in the penetration of renewable energy onto the Pacific Northwest grid will require new, flexible tools to maintain the reliability and resiliency of the grid.
- Energy storage is an excellent resource that provides value to the utilities for both generation and transmission services.
- Energy storage resources need to be evaluated beyond looking at just arbitrage alone; the values of ancillary services (frequency response, voltage regulation, energy imbalance, reserves, ramping up/down), peaking and peak shaving capabilities, and system optimization need to be quantified, analyzed and "stacked."

However, in their comments, GBEP believes that the UTC did not properly characterize the ability of advanced PSH to provide these critical and valuable services. The white paper states that, "modern technologies such as batteries and flywheels, with their ability to move between charging and discharging modes instantaneously, have opened up a new suite of services that energy storage can provide, such as frequency response, voltage regulation, and energy imbalance."

It is true that the domestic fleet of 40 domestic PSH facilities currently in operation are not responsive enough to compete against batteries and flywheels; these PSH plants were largely built out in the 1970's and 1980's and were paired with large thermal generators such as coal and nuclear. The equipment used was conventional fixed-speed pump/turbine units. Over the past two decades, a new class of PSH equipment has been developed and successfully deployed throughout Europe, Asia, and around the world.

The ternary technology that the Gordon Butte facility will utilize is the fastest responding pumped hydro technology available today for grid services. Ternary PSH can provide higher storage capacity with minimal maintenance over a 50+ year lifetime. Older conventional pumped storage plants operate in either generating mode or pumping mode. The fast response time and operational range of the modern ternary units are a result of their ability to operate both the pump and the turbine-generator simultaneously.

For traditional PSH, the transition between these two modes requires the unit coming to a full stop and dewatering of the unit before restarting in the opposite direction. The configuration of the ternary PSH has addressed this limitation, allowing the pump/turbine units to transition quickly from pumping to generating at an estimated 20-40 MW/second. This operational feature enables ternary to provide fast acting response to power system operational changes that are important to system reliability. At 400 MW of nameplate capacity, Gordon Butte PSH will be able to offer 800 MW of fast acting regulation capacity (the ability to generate 400 MW and pump 400 MW) and switch from pumping to generating and back again at approximately 20+ MW/sec.

The speed at which modern ternary units can operate makes the Gordon Butte PSH a large and robust "battery" that is able to provide storage over different periods of time including: hourly (energy arbitrage, renewable integration, ramping, peaking / peak shaving), sub-hourly for ancillary services, and fast acting (frequency control, regulation and essential reliability services).

PSH vs. Other Technologies

Washington has, for the past 20-years adopted policies that have focused on energy diversity (renewable energy generation) and greenhouse gas emission reductions through discouraging the use of fossil-fuel generation resources, encouraging the adoption of renewable energy generation and facilitating distributed technologies to is customers.[2] GBEP believes that PSE is correct in its decision to move away from selecting gas-fired resources to fill its near-term capacity needs. The selection of demand response and energy storage projects properly recognizes the economic advantages and environmental benefits of these flexible resources. However, GBEP believes that PSE's selection of a 4-hour flow battery as the preferred energy storage technology does not fully account for the operational realities of a battery called upon for grid regulation. This was explored in detail in the comments that GBEP filed on PSE's 2017 IRP.

PSH vs. Batteries

The selection of a 4-hour flow battery is based on the economics portrayed in Figure 6-20 [IRP, page 6-42] which shows a levelized net capacity cost of $93/kw-year, the lowest among the energy storage options evaluated. Pumped storage hydro comes in next lowest with a net capacity cost of $105/kw-year. However, the net capacity cost for all of the battery options is highly dependent on the assumed transmission and distribution (T&D) benefits which are $103/kw-year for a 4-hour flow battery. [IRP, page 6-41 and Figure 6-20, page 6-42] Without this assumed T&D benefit (which depends largely on an assumption that batteries will be placed in locations that will defer or eliminate significant

[2] Washington Utilities and Transportation Commission, *Modeling Energy Storage: Challenges and Opportunities for Washington Utilities,* May 2015. https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=U-151069

T&D investments), the 4-hour flow battery's net capacity cost increases to $196/kw-year, nearly twice the cost for pumped storage hydro. In fact, a reduction in the assumed T&D benefit of only 12%[3] results in a price parity between the 4-hour flow battery and pumped storage hydro, while a 50% reduction in the assumed T&D benefit results in a 37% higher cost[4] for the battery.

The Energy Storage Sensitivity [IRP, pages 6-58 and 6-59] concludes that replacing the 50 MW flow battery in PSE's Resource Plan portfolio with 50 MW of pumped storage hydro raises the portfolio's net present value (NPV) by $8 million. However, this result is again heavily influenced by the substantial T&D benefit assumed for the battery. If the assumed T&D benefit is reduced by 50%, the pumped storage hydro results in an NPV savings of $13 million.[5] If there is no T&D benefit for the battery, the pumped storage hydro NPV savings would increase to $34 million.[6]

It seems clear that the assumptions used to derive the T&D benefits of batteries during this analysis favored the 4-hour flow battery. GBEP is not convinced that this is an accurate representation of the projected locational impacts of batteries and ask that the underlying assumptions of this analysis are made transparent so that they may be objectively assessed.

In addition to its superior economics, pumped storage hydro is a mature technology with all of the ramping speed and flexibility, but none of the technology risks associated with utility scale batteries.

Battery Lifecycle Costs vs PSH (Degradation)

Battery degradation is another factor that must be considered when analyzing the cost/benefits of utility scale battery storage. It is known that batteries degrade and lose storage capacity over their lifetime.[7] The exact extent of this degradation is influenced by the operation of the battery, type of battery, and operating environment among other factors. However, due to the complex nature of the aging processes and the large number of variables, nearly all of the existing battery capacity degradation models rely heavily on theoretical data.[8] Other factors such as ambient temperatures, nature of the energy

[3] From $103/kw-year to $91/kw-year.
[4] $144.5/kw-year for 4-hour flow battery vs. $105/kw-year for pumped storage hydro
[5] 50% of NPV calculated in footnote 4.
[6] 50 MW * $58.81/kw-year T&D benefit (2018) with 2.5% annual escalation over 54 years at 7.77% discount rate with costs beginning in Year 5 = $42 million NPV
[7] Fortenbacher, P., & Andersson, G. (2017). *Battery Degradation Maps for Power System Optimization and as a Benchmark Reference.* Zurich: Power Systems Laboratory. *https://arxiv.org/pdf/1703.03690.pdf*
[8] Smith, K., Neubauer, J., Wood, E., Jun, M., & Pesaran, A. (2013, April 15). *Models for Battery Reliability and Lifetime.* Retrieved from NREL.gov

cycling, and depth of discharge all can negatively affect the batteries performance, increasing the overall lifecycle cost of the battery system.

Studies have shown that lithium-ion batteries have some very real problems with degradation. Testing on these batteries have demonstrated that they have a typical life of anywhere between 500-1200 cycles. A group from the University of South Carolina also performed research into the capacity fade of lithium ion batteries subjected to high discharge rates.[9] Their research concluded that lithium ion batteries that undergo rapid charging and discharging (as would be the case if the battery was used for grid regulation) would experience a capacity reduction of 16.9%, resulting in a reduced total capacity of 83.1%, after only 300 cycles. Other current estimates such as Lazard's *Levelized Cost of Analysis 2017* provide the lifecycle estimates of lithium ion batteries based on the assumption that the battery would <u>only be cycled once per day</u>.

As noted above, the 2017 IRP has selected a 4-hour flow battery as the preferred energy storage technology. Though flow batteries do not have all of the problems that accompany lithium-ion batteries, they still have their drawbacks. Flow batteries also suffer from degradation, although less research is available on the degradation rates, causes, and effects, leading to less conclusive information available about their life expectancy.

A recent study found that a vanadium redox flow battery was reduced to 60% of its original capacity after only 50 cycles. This capacity was then mostly restored by replacing the electrolyte and reversing the polarity of the battery.[10] This is an important finding since it indicates that although flow batteries are generally expected to have long lifetimes (beyond 10,000 cycles), they would not be maintenance-free over their lifetimes. The findings of this study suggest that the electrolyte would need to be replaced entirely or restored in some way to extend the life of the battery to a reasonable number of cycles.[11] This is corroborated in a Harvard article that describes research into a new type of flow battery.[12] The article plainly states that today's flow batteries are a promising

[9] Ning, G., Haran, B., & Popov, B. (2002, December 20). *Capacity fade study of lithium-ion batteries cycled at high discharge rates.* Retrieved from Sciencedirect.com: http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.704.1039&rep=rep1&type=pdf

[10] Derr, I., Bruns, M., Langner, J., Fetyan, A., Melke, J., & Roth, C. (2016, September 1). *Degradation of all-vanadium redox flow batteries (VRFB) investigated by electrochemical impedance and X-ray photoelectron spectroscopy: Part 2 electrochemical degradation.* Retrieved from Sciencedirect.com: http://www.sciencedirect.com/science/article/pii/S037877531630742X

[11] Derr, I. et al., 2016

[12] Burrows, L. (2017, February 9). *Long-lasting flow battery could run for more than a decade with minimum upkeep.* Retrieved from Harvard.edu: https://www.seas.harvard.edu/news/2017/02/long-lasting-flow-battery-could-run-for-more-than-decade-with-minimum-upkeep

solution, but suffer degraded energy storage capacity and require maintenance of the electrolyte. Overall, vanadium redox flow batteries are still a highly developing technology with some strong attributes as well as some distinct drawbacks.

As PSE continues to refine their approach of comparing energy storage technologies, GBEP would like to see a cost/benefit analysis that properly and accurately weighs the true lifecycle costs of battery storage technology.

E3 Lifecycle Cost Analysis of Storage / Capacity Resources

GBEP commissioned Energy+Environmental Economics (E3) Consulting to compare the lifecycle costs and performance of various technologies that can be used to provide energy storage, capacity, and ancillary services to better inform comparisons of different storage technologies and their suitability for use in various markets. The results of the *Analysis of the Capabilities and Lifecycle Costs of Storage / Capacity Resources* are summarized below and provided in Attachment A.

For this effort, E3 compared the total cost of providing flexible capacity and/or energy storage services across the lifetime of an advanced PSH asset, to the stream of investments that would be required to provide a comparable duration of service using other energy storage and conventional capacity resources. This lifecycle cost calculation incorporated the upfront capital costs of the technologies, the capital costs of any replacement purchases due to performance degradation or operating lifetime, and the continued operating and maintenance costs required to maintain each technology's capability to provide comparable services over that time period.

The results show that a clear benefit accrues to advanced PSH facilities due to their 50+ year service life and much longer duration of storage.

Additionally, E3 developed a framework for comparing the ability of different technologies to provide a wide array of energy, capacity, and ancillary service products across markets that have different needs for each of these services. E3 developed a matrix that assessed each technology's ability to provide the various services based on the operating characteristics of the technology and the type of service needed. This included a discussion of whether the technology would have to be exclusively tasked with providing that service or whether it could be operated in such a way that it could provide multiple services simultaneously.

Gas-fired resources

GBEP believes that the 2017 Integrated Resource Plan (2017 IRP) understated the cost competitiveness of energy storage technologies versus gas-fired resources in two ways.

1) PSE did not assign carbon costs to gas peakers because carbon costs were modeled using the specific provisions of the EPA's then-proposed Clean Power Plan which applied only to baseload units. [IRP, pages 1-4, 2-11 and 4-15] Addition of carbon costs to the gas peakers would improve the relative cost effectiveness of the energy storage technologies.

2) PSE assumes in the 2017 IRP that it has enough intra-hour flexibility in its existing generation fleet that it does not need to add new flexible capacity resources. This is based on the analysis presented in the 2017 IRP's Appendix H, Operational Flexibility. That analysis is based on PSE's current generation fleet and flexibility requirements. It does not include possible future increased flexibility requirements that could result from building new variable resources inside PSE's balancing area or moving existing variable resources (such as Hopkins Ridge, Lower Snake River and Wild Horse). These possible future flexibility requirements cannot be effectively met by inflexible frame peakers.

While these future flexibility needs could conceivably be met by more flexible gas units such as aeroderivative CTs or reciprocating engines, energy storage technologies can perform these duties much more economically because their two-way capability (full output to full storage) effectively doubles their flexible operating range compared to nameplate capacity. For example, Gordon Butte is able to generate at 400 MW (+100%) and store energy through pumping at 400 MW (-100%) giving it a flexible operating range of 800 MW. GBEP commissioned E3 Consulting to compare ternary pumped storage hydro technology against gas peakers (aeroderivative CTs, reciprocating engines and frame CTs) for various flexible capacity products. The results of this study are provided as Attachment B and demonstrate that pumped storage hydro provides these flexible capacity products at a significantly lower cost.

Montana Wind + Pumped Storage Hydro

The Gordon Butte Pumped Storage Hydro Project is located approximately six miles from its planned interconnection point with the Colstrip 500 kV transmission lines. Gordon Butte is a natural complement to Montana wind; packaging wind and storage together provides a dispatchable renewable energy product for a cost-effective replacement for PSE's share of Colstrip 1&2, all while leveraging PSE's investment in the Colstrip Transmission System. Montana wind and pumped storage hydro could share PSE's Colstrip transmission rights freed up by the retirement of Colstrip 1&2 with the pumped storage resource optimizing the use of this transmission capacity.

GBEP commissioned a study by E3 Consulting of replacement options for PSE's share of Colstrip 1&2. That study, which is provided as Attachment C to these comments, showed a substantial savings to PSE by procuring a package made up of Montana wind and pumped storage hydro rather than a package made up of Washington wind and gas peakers.

PSE's 2017 IRP selects Washington solar over Montana wind for PSE's renewable energy needs and batteries over pumped storage hydro for capacity. GBEP has not had sufficient time to prepare a detailed study comparing a package of Montana wind and pumped storage hydro to a package of Washington solar and batteries. However, a straightforward comparison of capital costs for replacing PSE's Colstrip 1&2 capacity (300 MW) and energy (250 aMW) has been prepared using cost and other parameters from the 2017 IRP [Figure 4-18, page 4-32 and Figure D-20, page D-43]. As shown in the tables below, the Montana wind and pumped storage hydro alternative, results in a <u>capital cost savings of 50% or $1.4 billion and an additional 100 MW of effective capacity</u>.

Colstrip 1&2 Carbon-Free Replacement Alternatives

Montana Wind and Pumped Storage Hydro							
Resource	Nameplate Capacity	Capacity Factor	Energy	Capacity Credit	Effective Capacity	Capital Cost	Capital Cost
	(MW)		(aMW)		MW	($/kw)	$million
MT Wind	543	46%	250	49%	266	$ 2,055	$ 1,117
PSH	134			100%	134	$ 2,400	$ 322
Total	677		250		400		**$ 1,438**

Washington Solar and Batteries							
Resource	Nameplate Capacity	Capacity Factor	Energy	Capacity Credit	Effective Capacity	Capital Cost	Capital Cost
	(MW)		(aMW)		MW	($/kw)	$million
WA Solar	962	26%	250	0%	0	$ 2,041	$ 1,963
Batteries	395			76%	300	$ 2,324	$ 917
Total	1356		250		300		**$ 2,880**

Colstrip Transmission System (CTS) & BPA Montana Intertie (MI) Costs

Although rates have been established for PSE's CTS capacity under their FERC Open Access Transmission Tariff (OATT), PSE's costs for the CTS and MI have historically been recovered in retail rates. The Colstrip Transmission Agreement does not provide an opportunity for PSE to reduce its CTS ownership percentage and associated costs when Colstrip 1&2 are retired. Similarly, the Montana Intertie Agreement allows BPA to continue to charge PSE for its full contracted MI capacity following the retirement of Colstrip 1&2.

Based on these contractual provisions, several stakeholders[13] argued during the IRPAG process that costs for CTS and MI transmission capacity freed up by the retirement of PSE's share of Colstrip 1&2 should be treated as sunk costs rather than being included as added costs for accessing Montana resources. PSE disagreed and declined to run any scenarios or sensitivities that treated the CTS and MI costs as sunk.

In defending its treatment of these costs, PSE argued that if it did not use this transmission capacity to import power from Montana, the capacity could be resold to others under the OATT. This assertion should be viewed with skepticism for two reasons:

- First, PSE has historically had excess CTS transmission capacity that has been available under the OATT, but not purchased by third parties. The costs for this excess "stranded" capacity have historically been recovered in retail rates.
- Second, if PSE's analysis in the IRP is correct that Pacific Northwest solar is more cost effective than Montana wind burdened with CTS and MI costs, other Pacific Northwest utilities may reach a similar conclusion, resulting in no market for PSE's Colstrip 1&2 CTS and MI capacity.

The Commission should direct PSE to treat CTS and MI costs as sunk in the RFP evaluation of Montana resources that would be accessed using this transmission capacity. In the alternative, the Commission should advise PSE that its shareholders may be at risk for any stranded costs associated with this capacity if PSE declines to acquire otherwise cost-effective resources from Montana (assuming CTS and MI costs are treated as sunk), and the freed-up CTS and MI capacity is not purchased by third parties.

Redirect of BPA transmission rights from Garrison to Mid-C

The RFP notes that 300 MW of BPA transmission rights (historically used to deliver PSE's share of Colstrip 1&2 from Garrison, MT to PSE's system) could be redirected to Mid-C or other available receipt points on the BPA system. PSE should not let this redirect possibility become a factor that results in a failure to acquire otherwise attractive resources from Montana. Any assumption about redirecting these rights would be speculative and this strategy could come with serious drawbacks.

First, the Commission has expressed its concerns about PSE's current level of market reliance in its comments on the IRP.[14] Redirecting transmission rights historically used to deliver a long-term resource to allow for greater market purchases would appear to be doubling down in an area where PSE is already exposed to significant risk.

[13] Absaroka Energy, Orion Renewables, Renewable Northwest, Sierra Club and Climate Solutions

[14] Dockets UE-160918 and UE-160919, WUTC Acknowledgment Letter Attachment (May 7, 2018), pages 5 and 6.

Second, redirecting these transmission rights significantly increases the odds that PSE's CTS and MI capacity historically used to deliver PSE's share of Colstrip 1&2 will become effectively stranded. These CTS and MI costs would continue to be borne by PSE's retail ratepayers with no beneficial use of these assets.

Dynamic Transfer Capability

In order to maximize the value of a Montana pumped storage hydro project, the resource must be effectively incorporated into PSE's balancing authority (BA). This requires dynamic transfer capability (DTC) to deliver the real-time output of the pumped storage project to PSE's BA.

The IRP describes certain technical and process challenges to arranging for dynamic transfers from Montana. In early 2018, BPA Administrator Elliot Mainzer and Montana Governor Steve Bullock convened a forum to develop a Montana Renewables Development Action Plan (MRDAP) to address barriers to exporting Montana clean energy resources to the Pacific Northwest and identify potential solutions. Among the issues being addressed in the MRDAP process is DTC. Results to date are very encouraging:

- There are no DTC limits on the CTS.
- BPA can accommodate dynamic transfers of approximately +/- 170 MW across its transmission system between western Montana and PSE with existing transmission facilities and operating practices.
- BPA's available DTC from western Montana to PSE can be doubled to approximately +/- 340 MW with the automation of a single existing reactor at BPA's Garrison, MT substation.
- There are no known limits on DTC between the BPA and PSE BAs.

The MRDAP process will be completed and a final report issued by the end of June, well before RFP responses will be submitted and evaluated. PSE should incorporate the findings of the MRDAP process into its evaluation of RFP resources and should not decline to acquire Montana resources due to unfounded concerns about DTC.

On-line date of 2023

In the 2018 RFP, Section 2. Resources Requested, PSE states that "existing and yet-to-be-constructed resources with commercial operation dates through September 21, 2022 for capacity resources and December 31, 2022 for renewable resources are *eligible* to participate [in the 2018 RFP]." GBEP encourages PSE not to disqualify capacity/energy storage projects that have a commercial on-line date shortly after 2022, but should give these resources equal consideration in the RFP evaluation process. Failing to consider resources that could be available soon after 2022 would be especially short-sighted, given the long lives and associated long-term benefits associated with resources that may be procured though the RFP.

Large Projects not fitting well into RFP

In October of 2017, the Washington UTC issued the *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition*. GBEP believes that this report correctly identifies the historic problems of evaluating energy storage, particularly utility-scale projects such as the Gordon Butte PSH, through the traditional utility planning process. The reality is that large, capital-intensive projects provide value and benefit that is spread across the generation, transmission and distribution networks of a utility company, and offer products that not properly accounted for during the planning and acquisition processes.

The Washington UTC's succinctly summed up the issue: "Historically, utility resource planning has taken place within the independent silos of generation, transmission, and distribution. Energy storage can act in any one of those functions, but the challenging corollary is that to generate sufficient benefits to offset its cost, it will most likely be required to act in more than one function. In a planning regime that narrowly looks at the functions separately, energy storage is unlikely to appear cost effective through the lens of any single function, which appears to be one likely reason that past IRPs have not determined energy storage technologies should be included in a utility's resource mix." GBEP endorses the following guidelines outlined in the October 2017 Washington UTC report, and encourages PSE to ensure that energy storage is properly evaluated during the 2018 RFP process.

- The many value streams provided by energy storage should be stacked to provide a wholistic representation of benefits
- Energy storage should be credited for benefits across generation, transmission and distribution sides of the utility's network
- Energy storage should be modeled on a sub-hourly basis to better capture the operational benefits of instantaneously available bulk energy storage
- PSE should allow stakeholders access to their modeling assumption and results, and recommend alternative scenario recommendations if warranted
- PSE and the Washington UTC should consider alternative procurement strategies for large energy storage facilities that are not properly valued in a traditional utility procurement process

Conclusions

In addition to the points outlined above, GBEP offers the following as a summary of our comments on PSE's Draft 2018 RFP.

- GBEP is developing the Gordon Butte Pumped Storage Hydro Project, a 400 MW, closed-loop pumped storage hydro project with 3,400 MWh of storage capability to be interconnected to the Colstrip 500 kV transmission lines near Martinsdale, Montana. Gordon Butte has completed its licensing and development activities and is construction-ready.
- The speed at which modern ternary units can operate makes the Gordon Butte PSH a large and robust "battery" that is able to provide storage over different periods of time including: hourly (energy arbitrage, renewable integration, ramping, peaking / peak shaving), sub-hourly for ancillary services, and fast acting (frequency control, regulation and essential reliability services).
- In addition to its superior economics, pumped storage hydro is a mature technology with all of the ramping speed and flexibility, but none of the technology risks associated with utility scale batteries.
- As PSE continues to refine their approach of comparing energy storage technologies, GBEP would like to see a cost/benefit analysis that properly and accurately weighs the true lifecycle costs of battery storage technology.
- Gordon Butte is a natural complement to Montana wind; packaging wind and storage together provides a dispatchable renewable energy product for a cost-effective replacement for PSE's share of Colstrip 1&2, as well as a package of firm, clean energy for Washington businesses and customers (see chart on page 8).

Recommendations for RFP

- PSE should not acquire any new gas-fired resources through this RFP. It would be inappropriate to do so in the absence of a comprehensive analysis of PSE's future flexible capacity needs presented and reviewed in a public setting such as the IRP process.
- In evaluating batteries in the RFP, PSE should develop specific estimates of T&D locational benefits for each proposal rather than relying on generic estimates of locational benefits.
- Costs associated with CTS and MI transmission rights historically used for delivery of PSE's share of Colstrip 1&2 should be treated as sunk, rather than incremental, costs when evaluating Montana resources in this RFP.
- PSE should incorporate the results of the MRDAP process, especially with regard to DTC, in evaluating RFP resources. PSE should not decline to acquire Montana resources due to unfounded concerns about DTC.
- PSE should not let the possibility of redirecting its BPA transmission rights from Garrison, MT to PSE become a factor that results in a failure to acquire otherwise attractive resources from Montana. Any assumption about redirecting these rights would be speculative and this strategy could come with serious drawbacks, including increased market reliance and stranding of valuable CTS and MI transmission capacity.

- PSE should not disqualify capacity/energy storage projects that have a commercial on-line date shortly after 2022. These resources should be given equal consideration in the RFP evaluation process.

Attachment A

Analysis of the Capabilities and Lifecycle Costs of Storage / Capacity Resources

Energy+Environmental Economics

Analysis of the Capabilities and Lifecycle Costs of Storage / Capacity Resources

Prepared for Absaroka Energy

4/2/2018

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Outline

- Project Goals
  - Technologies for comparison
- Lifecycle Cost Analysis
  - Methodology
  - Data Sources
  - Sensitivities
- Service Provision Matrix
- Market Requirements
- Appendix

Energy+Environmental Economics

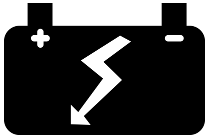
Project Goals

Project Goals

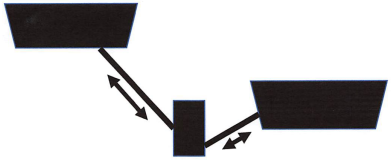
- **Absaroka Energy LLC has asked E3 to analyze the lifecycle costs for different generation and storage technologies**
  - Show costs on a levelized $/kW-yr. basis over the entirety of a utility planning horizon to allow apples-to-apples comparison
  - Include replacement costs for batteries
    - Accounting for expected improvements in battery technology over the lifetime of the analysis
- **Compare the suitability of different generation and storage technologies for providing energy, capacity, and ancillary services**
- **Describe different market characteristics that influence the value of different services across markets**

Technologies for Comparison

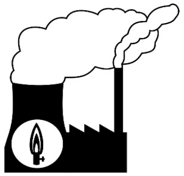
+ **This analysis focuses on technologies that compete to provide capacity and ancillary services**
  - Battery Storage
    - Lithium Ion
    - Vanadium Flow



  - Hydro Pumped Storage
    - Ternary Pumped Hydro
    - Conventional Pumped Hydro



  - Natural Gas Peakers
    - Frame Turbine
    - Aeroderivative CT
    - Reciprocating Engine



+ **Other technologies may be able to provide some of the services listed, but were not included in this analysis**
  - Combined cycle natural gas plants
    - Improved performance may allow combined cycle plants to provide ancillary services
  - Compressed Air Energy Storage (CAES) projects
    - Including Liquid or Cryogenic Air Energy Storage

Energy+Environmental Economics

Lifecycle Cost Analysis

Lifecycle Cost Analysis

+ Methodology

- E3 has adapted the pro forma used in the California IRP process to reflect ongoing costs of maintaining battery and combustion turbine operation at the level of a hydro pumped storage facility
- Future investments are financed at the same debt-equity ratio as initial capital expenditure, and receive similar tax treatment (MACRS)
- Costs are levelized over the lifetime of the investment to arrive at a single $/kW-yr. number

Lifecycle Cost Analysis

- **Costs per kW are calculated based on the resource nameplate capacity**
  - The ability of batteries and pumped storage to absorb as well as discharge gives them a wider range of potential **useful capacity**
- **Batteries are replaced / augmented over the lifetime of a pumped storage unit**
  - Battery cell costs are projected to decrease in coming years
  - Some investments (buildings, durable equipment) may have longer lifetimes than others (battery cells)
  - Battery lifetime is heavily dependent on usage assumptions; this analysis assumes they are operated as “peaker” replacements
- **Gas peakers are replaced at the end of their 30-year lifetime**

Lifecycle Cost Analysis

+ Methodology Details

- The E3 pro forma model **minimizes** equity share of initial investment subject to:
  - **minimum equity share of 20%**; and
  - sufficient cash flow to achieve a **debt service coverage ratio of 1.40** through the initial investment
- All costs were calculated using this pro forma (including the D/E optimization) to ensure comparability of results

+ E3 conducted additional analyses to determine the sensitivity to some key uncertainties

Cost Assumptions

+ Pumped Hydro Storage

- **Ternary pumped hydro** costs are based on financial projections from the Absaroka team for the Gordon Butte Pumped Hydro facility
- **Conventional pumped hydro** costs are based on costs prepared by E3 for the Western Electricity Coordinating Council

+ Batteries

- Costs for both **Li-Ion** and **Vanadium Flow** batteries is based on cost estimates for "Peaker Replacement" (100 MW) batteries in Lazard's *Levelized Cost of Storage v3.0* study
  - Use case for "Peaker Replacement" batteries is described* as "Large-scale energy storage system designed to replace peaking gas turbine facilities" that is fully charged and discharged every day

+ Natural Gas Peakers

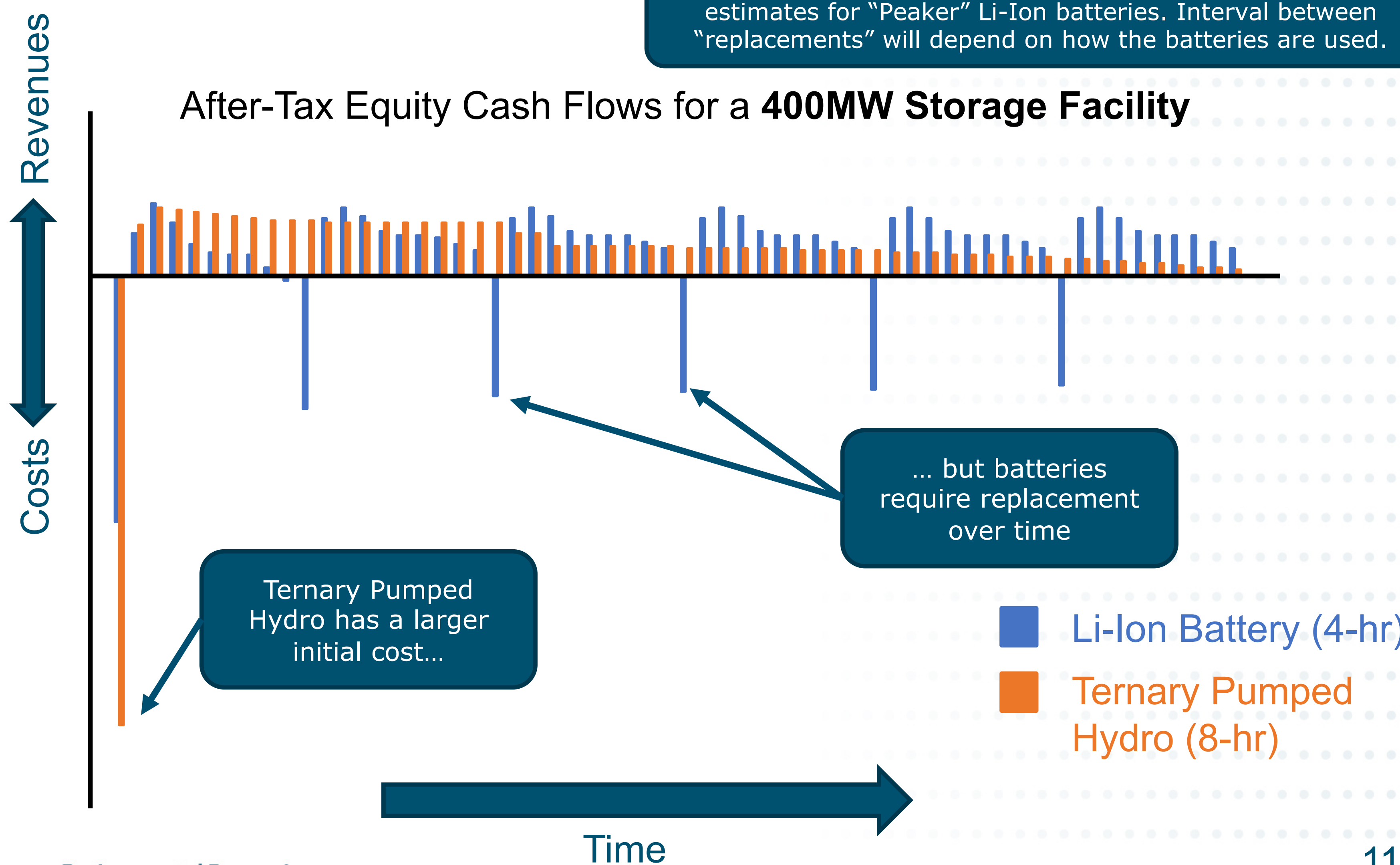
- Costs for **Frame Turbines**, **Aeroderivative CTs**, and **Reciprocating Engines** are taken from the Northwest Power and Conservation Council's *Seventh Power Plan*

+ Details on the resources modeled are shown in the Appendix

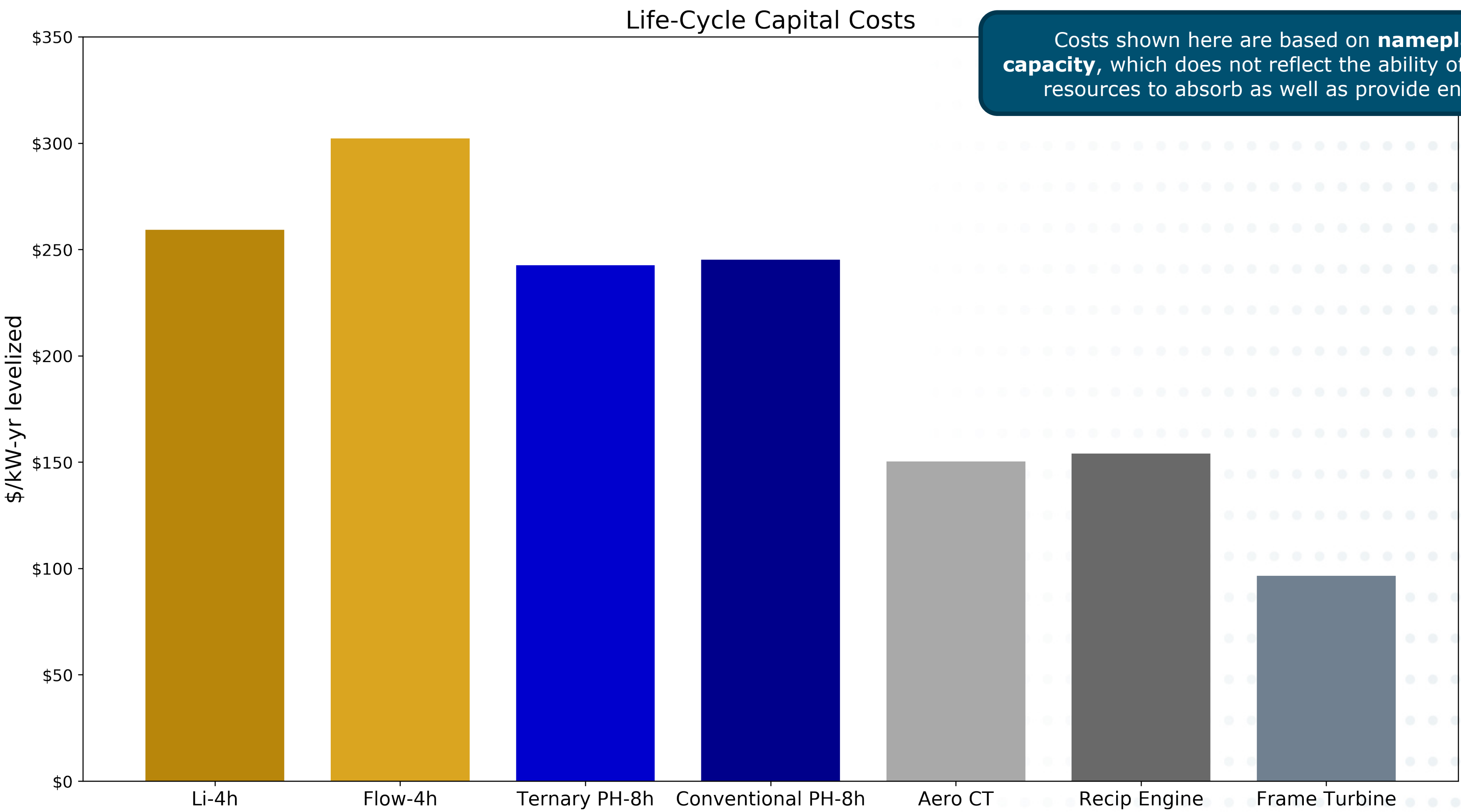
* Lazard *Levelized Cost of Storage*, pp. 8-9

Sample Cost Streams

Sample battery costs are based on Lazard (2017) cost estimates for "Peaker" Li-Ion batteries. Interval between "replacements" will depend on how the batteries are used.



Under default assumptions, lifecycle cost of Li-Ion is comparable to cost for Ternary PH



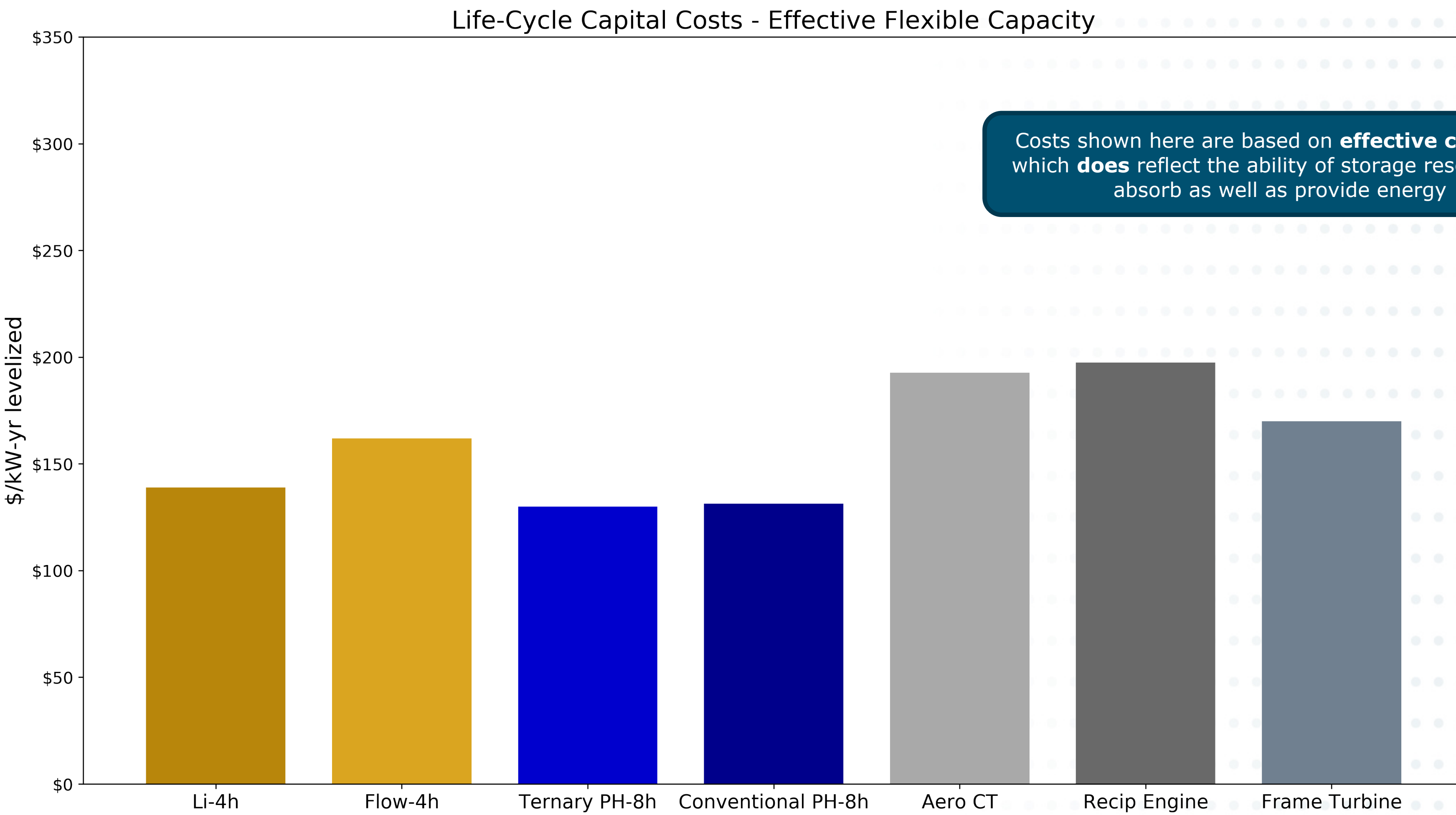
Costs shown here are based on **nameplate capacity**, which does not reflect the ability of storage resources to absorb as well as provide energy

Chart compares the levelized cost of **batteries with 4-hour (4h) storage duration** to **pumped hydro with an 8-hour (8h) storage duration**

Nameplate kW understates the flexibility of storage resources

- **Energy storage resources, unlike conventional generators, can act as both load *and* generator**
  - For example, they can provide energy to the grid when renewable energy is scarce and absorb excess renewable energy during periods of overgeneration
- **The ability to move from fully discharging to fully charging doubles the "effective capacity" of storage**
  - This can be helpful when providing regulation up / down or load following services
- **In contrast, the "effective capacity" of conventional resources is limited by minimum generation constraints**
  - "Effective capacity" for gas peakers will be **less** than the nameplate capacity

When compared on the basis of "flexible capacity", storage resources are competitive with gas peakers



Costs shown here are based on **effective capacity**, which **does** reflect the ability of storage resources to absorb as well as provide energy

Chart compares the levelized cost of **batteries with 4-hour (4h) storage duration** to **pumped hydro with an 8-hour (8h) storage duration**

Sensitivity Analysis

+ **Results of the cost comparison will vary depending on the assumptions used to generate the levelized numbers**
  - Long time frame for analysis leads to uncertainty, especially given expected changes in battery costs as technology matures
+ **E3 conducted some sensitivity analyses to determine which assumptions are key drivers**
  - Results presented above show costs based on best data currently available, while those that follow focus on showing the magnitude of uncertainties
+ **Slides below show sensitivity of results to variations in:**
  - Technology lifetimes
  - Capital cost projections
  - Variations in financing assumptions
  - Fixed O&M Costs
    - including warranty costs associated with maintaining battery output over the lifetime of the resource

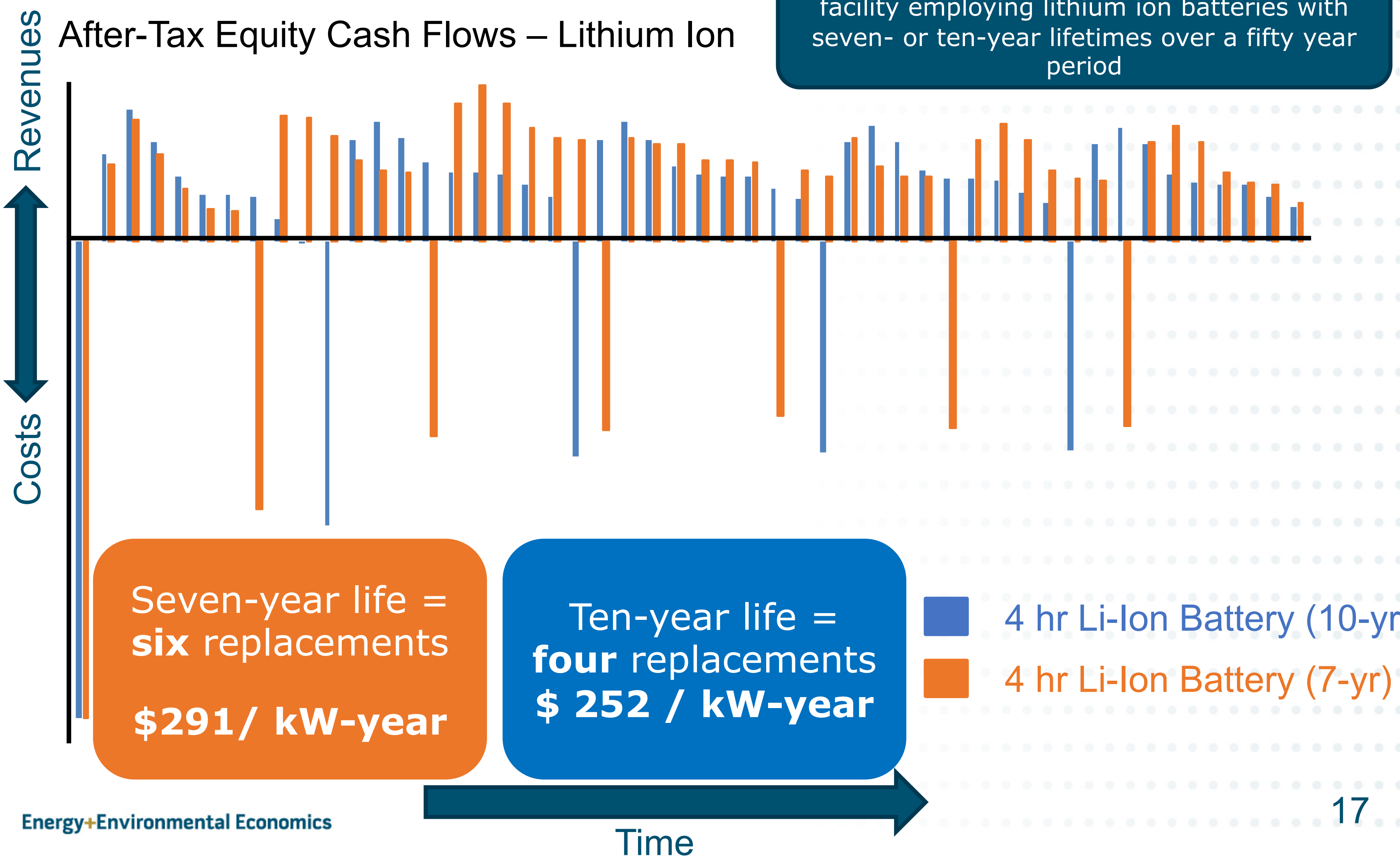
Lifetime of batteries is crucial, and will depend on how they are used

+ **For the results presented above, E3 assumed a 10-year lifetime for the batteries**
  - Lazard lifetime estimates are as high as 20 years, while NREL* recently estimated 7-10 years for Li-Ion batteries
    - This estimate assumes a single charge/discharge per day, which may not be consistent with how batteries would be used for regulation services
  - Lifetime and performance will depend on how storage resources are used and environmental conditions
+ **E3 examined the effect of changing battery sizes and lifetimes on the lifecycle cost of batteries**
  - Following slide shows the range (using low to high Lazard estimates, described fully on slide 18) of levelized costs assuming lifetimes from 5 to 20 years
  - Dotted line indicates the levelized cost of ternary pumped hydro resources

* See https://www.nrel.gov/docs/fy17osti/67102.pdf

Minor changes in the lifetime of the modeled asset can have large impacts on results

This figure compares cashflows for a storage facility employing lithium ion batteries with seven- or ten-year lifetimes over a fifty year period

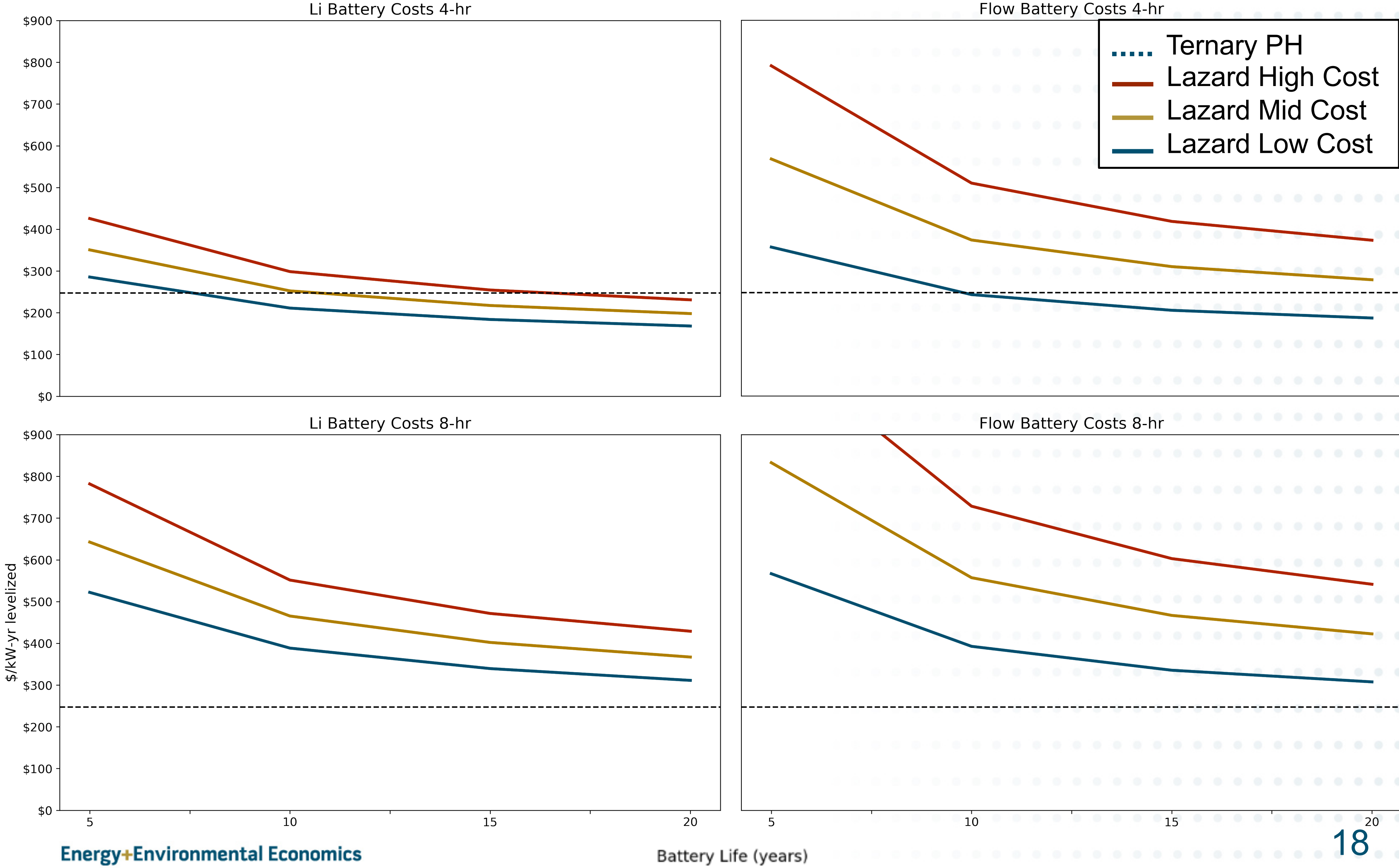


Seven-year life = **six** replacements

$291/ kW-year

Ten-year life = **four** replacements **$ 252 / kW-year**

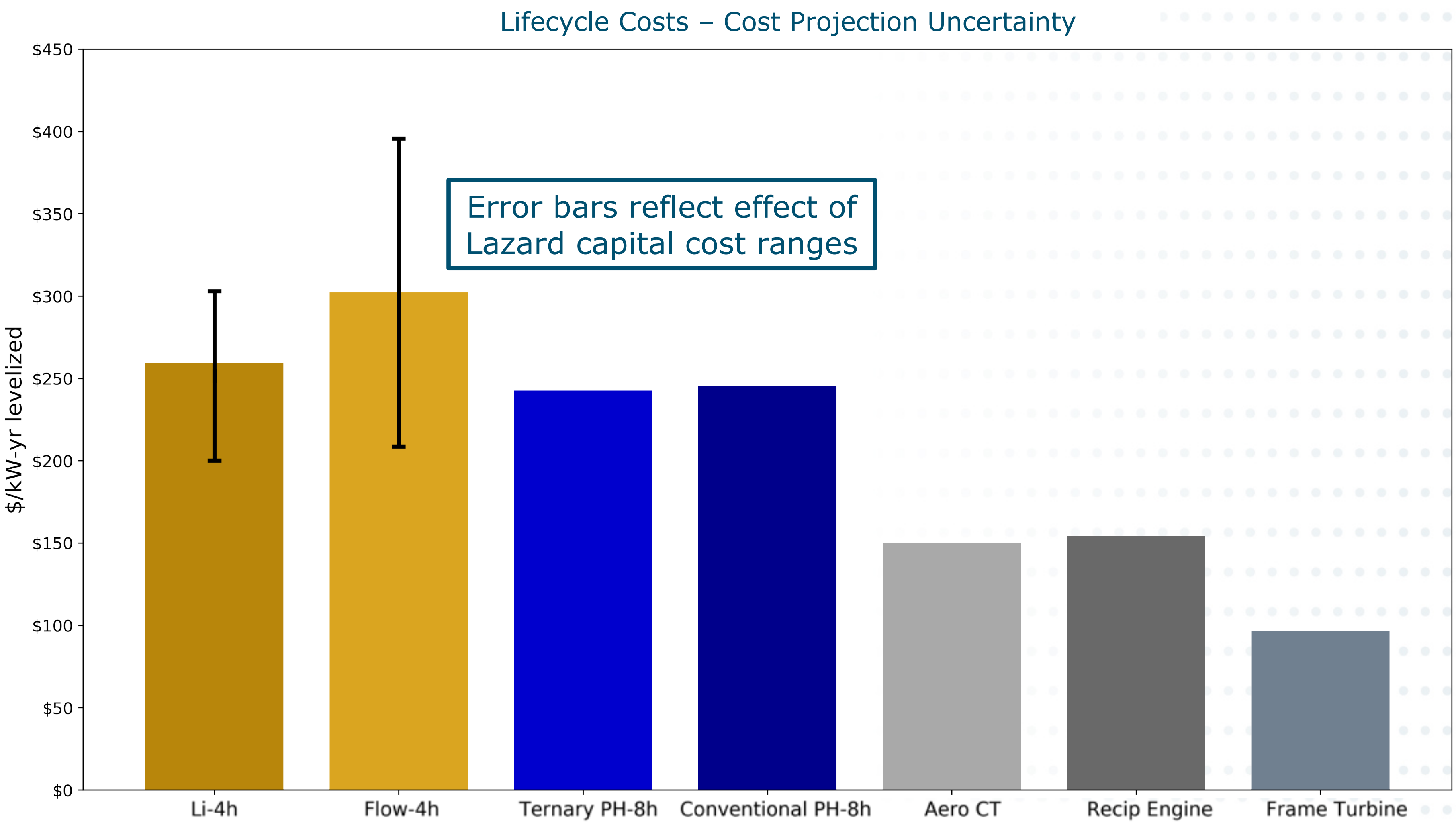
Battery cost, duration and lifetime sensitivities
The cost of batteries relative to ternary PH depends on duration and system lifetime



Comparison between pumped hydro, battery and natural gas peaker units is influenced by battery cost assumptions

+ **Given their limited deployment in the power sector, capital costs for battery storage are rapidly changing**
  - Battery storage capital costs have come down in recent years, and further reductions are expected
  - Lazard provides a range of battery cost estimates to reflect the magnitude of this uncertainty
  - Future battery costs will depend on the extent to which batteries are deployed and the learning rate achievable in the industry
+ **In comparison, natural gas and pumped hydro technologies are more stable, given power sector experience**
+ **The following slides show the effect of variations in cost assumptions on the levelized cost analysis**
  - Variations in the evolution of capital costs over time
    - Sets bounds for expected levelized costs given best available information
  - Variations in the magnitude of fixed O&M costs
    - Lifecycle costs for batteries are more sensitive to changes in Fixed O&M assumptions than pumped storage or gas peaker resources

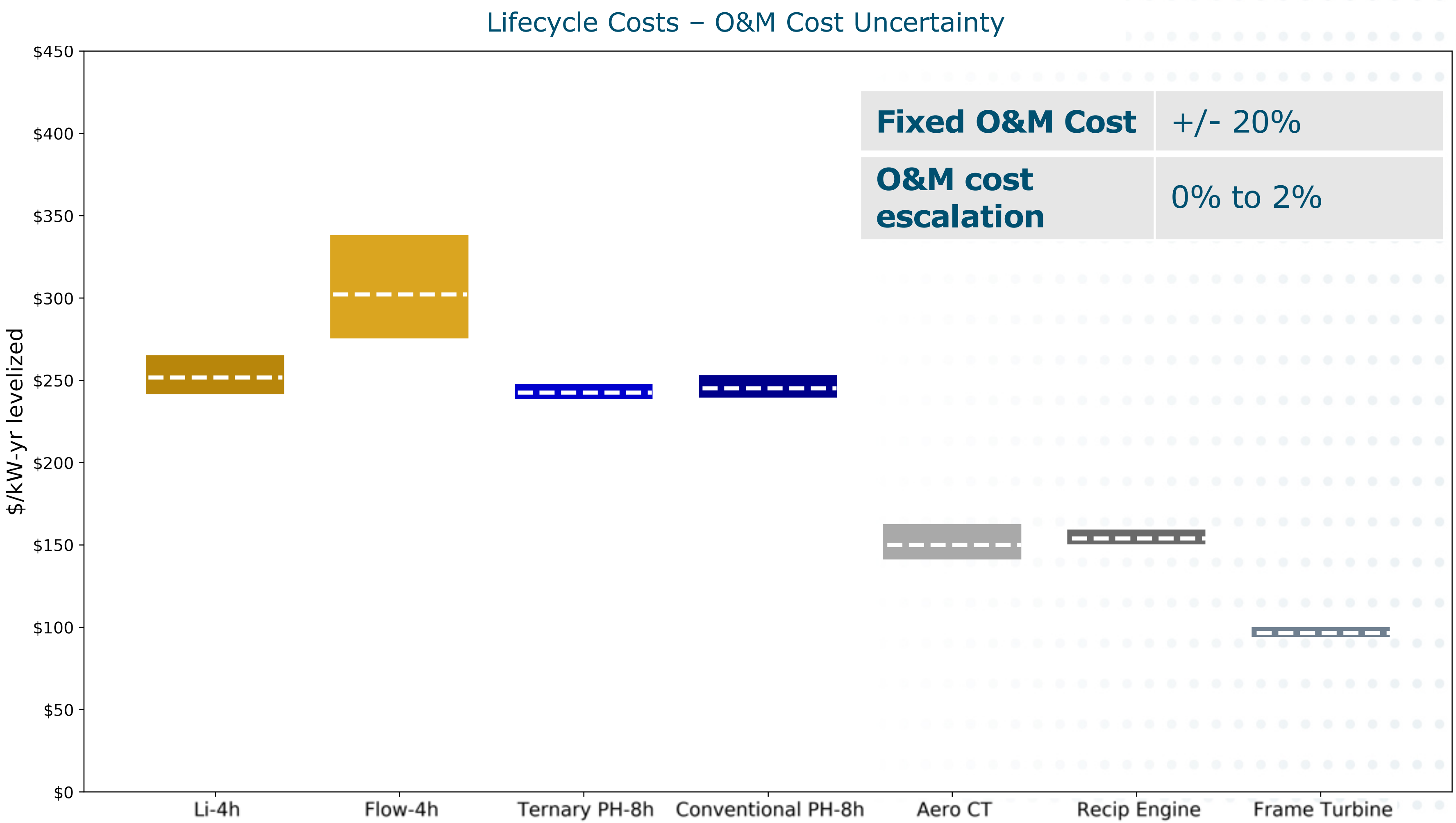
The largest source of cost uncertainty in this analysis is the capital cost of battery storage



Battery lifetime and degradation based on Lazard "Peaker Replacement" assumptions

Chart compares the levelized cost of **batteries with 4-hour (4h) storage duration** to **pumped hydro with an 8-hour (8h) storage duration**

Variation in fixed O&M costs affects batteries more than pumped hydro due to warranty costs



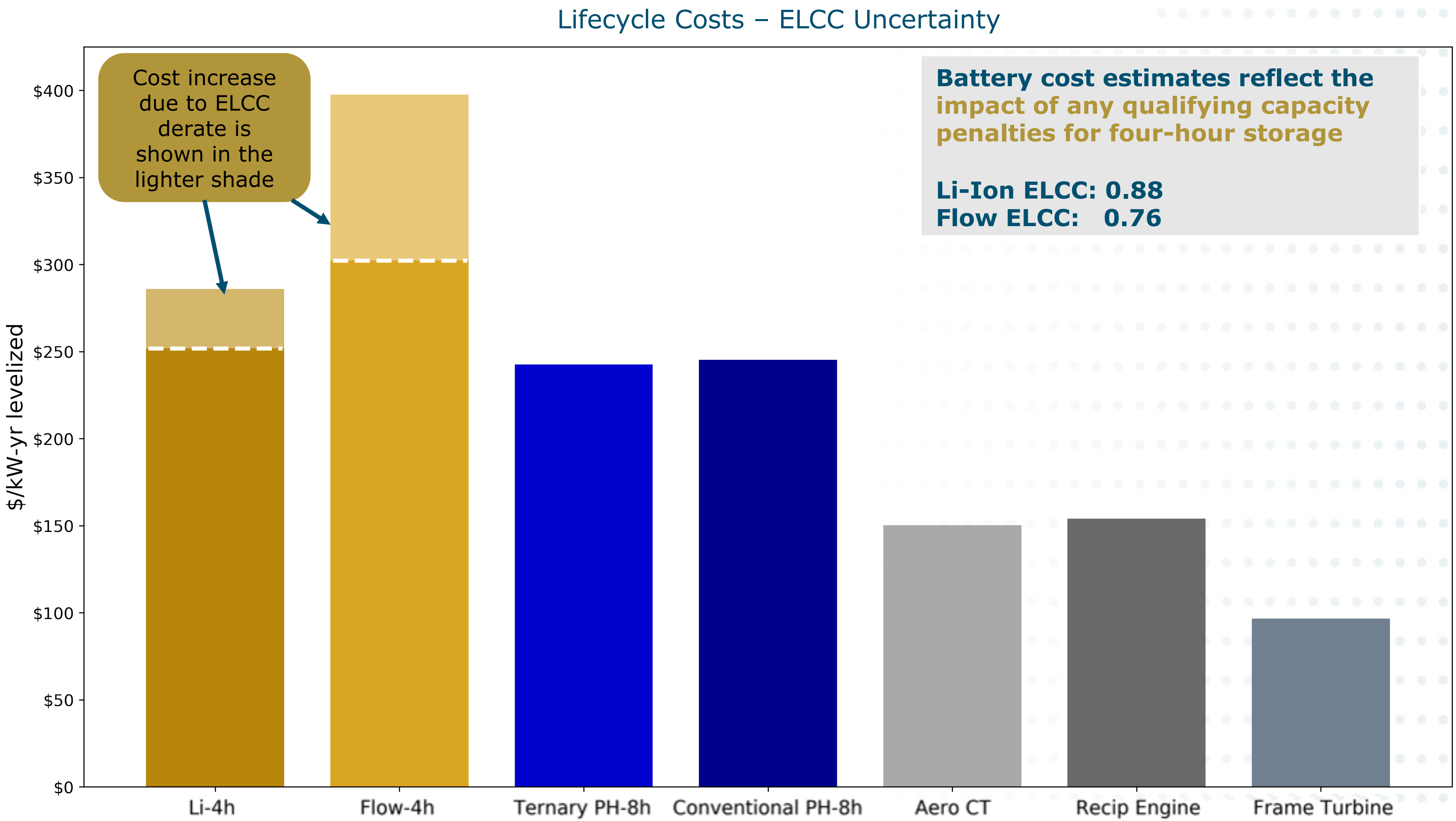
Fixed O&M Cost	+/- 20%
O&M cost escalation	0% to 2%

Battery lifetime and degradation based on Lazard "Peaker Replacement" assumptions

Storage duration can determine the capacity credit afforded to different resources

+ **In some IRPs, capacity of storage resources is discounted when calculating resource adequacy due to uncertainty regarding state-of-charge during peak hours**
  - Batteries and pumped storage cannot provide capacity if they have not recently been charged
+ **Discount depends on duration of storage**
  - Puget Sound Energy counts 66% of 2-hr battery storage, 80% of 4-hr
  - 8-hr storage resources (like pumped hydro) are treated like dispatchable generators
+ **Therefore, costs can also be compared on a the basis of the *effective load carrying* capacity**
  - Following chart shows the impact of reducing the qualifying capacity to 80% for the 4-hr battery

Battery storage capital costs may increase in planning contexts that use an ELCC (capacity derate) methodology



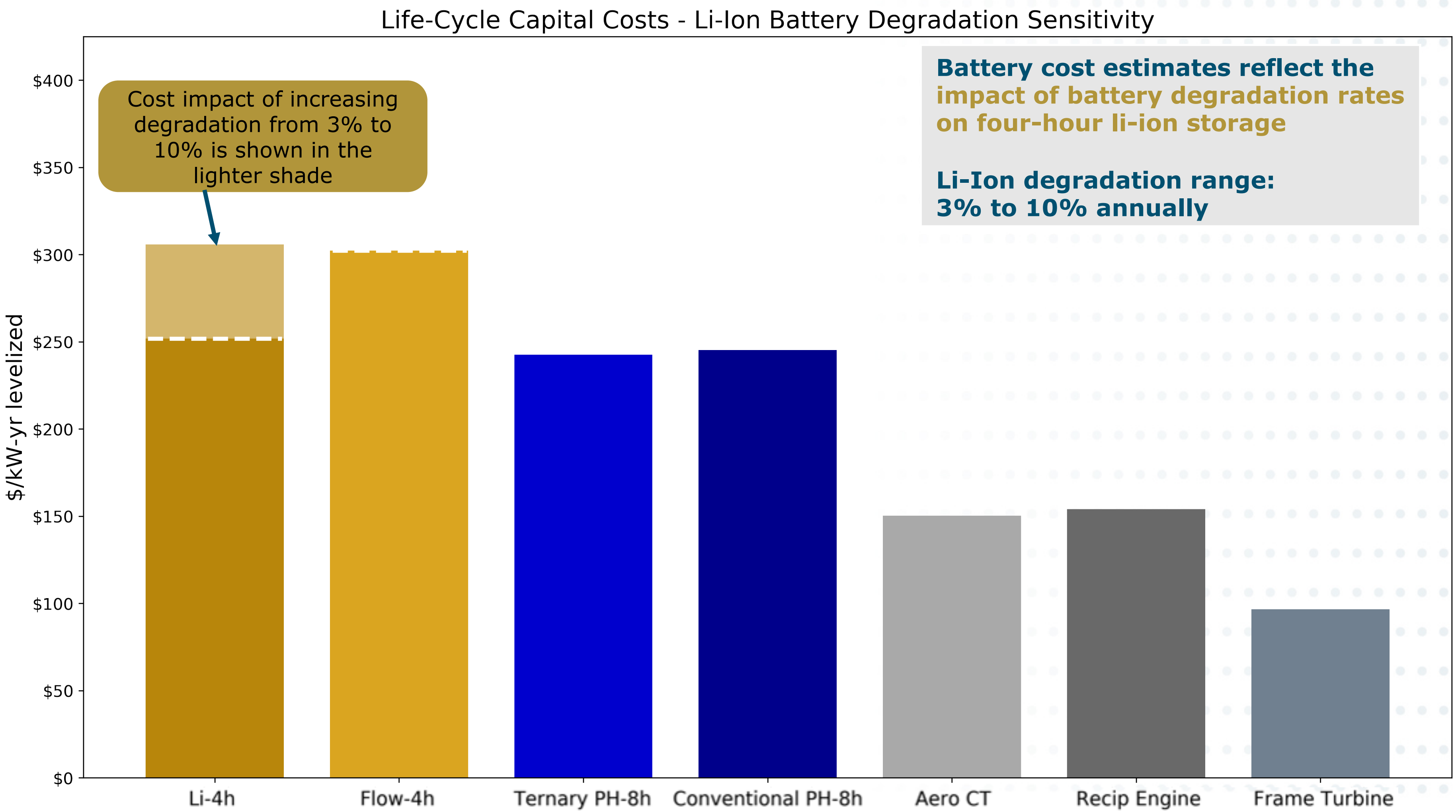
Battery cost estimates reflect the impact of any qualifying capacity penalties for four-hour storage

Li-Ion ELCC: 0.88
Flow ELCC: 0.76

Battery lifetime and degradation based on Lazard "Peaker Replacement" assumptions

Chart compares the levelized cost of **batteries with 4-hour (4h) storage duration** to **pumped hydro with an 8-hour (8h) storage duration**

Lithium-ion costs are sensitive to assumptions about degradation



Battery lifetime based on Lazard "Peaker Replacement" assumptions

Chart compares the levelized cost of **batteries with 4-hour (4h) storage duration** to **pumped hydro with an 8-hour (8h) storage duration**

Battery costs are still uncertain

- **E3 has estimated the cost of ongoing cell replacement to maintain given levels of service, but battery costs may still not fully reflect:**
  - **Warranty costs**
    - Some suppliers are offering battery installations with warranties to guarantee service over time
    - The specific details and duration of these warranties may vary, as will costs
    - Current analysis assumes warranty is priced to cover cost of adding cells to existing installations to compensate for degradation, and treated as a fixed O&M cost
  - **Disposal costs**
    - There may be end-of-life costs associated with battery disposal, which are currently unknown because the markets for grid-scale Li-ion and Flow batteries are not yet mature
    - E3 looked at disposal costs up to 10% of the initial capital cost and the effect was minimal
      - Most of these costs occur years in the future, so their impact is heavily discounted relative to near-term expenditures

Interpreting levelized cost results

- **There is still limited information on the relationship between battery operations and lifetime**
  - Rapid charge-discharge cycles may significantly reduce battery life relative to the daily charge-discharge cycles assumed by Lazard
  - Results of this comparison, as shown by the sensitivities around battery lifetime, are very sensitive to battery lifetime
- **Levelized cost per nameplate kW may undervalue the flexibility of storage resources**
  - In a high renewable world, a storage resource's flexibility to absorb excess renewable generation may provide value for system planners beyond the natural gas peakers they replace
- **The results considered here do not account for the effect of any carbon policies**
  - Cap-and-trade or carbon tax would hurt the cost effectiveness of natural gas generation

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Service Provision Matrix

Service Provision Matrix

- **E3 assessed the ability of each of the different resources (pumped storage, battery, gas peakers) to provide the following services:**
  - Energy
    - Both energy provision and absorption of overgeneration
  - Firm Capacity
  - Locational Benefits
  - Ancillary services
    - Load Following, Regulation, Frequency Support, Spin/Non-Spin Reserves
- **The following slides compare each technology's technical ability to provide the various services needed in energy systems**

Service Provision Matrix

Excellent	
Good	
Okay	
Poor	

Technology	Batteries		Pumped Storage		Simple Cycle Natural Gas		
Example Unit	Li-Ion	Vanadium Flow	Adjustable Speed Reversible Pumped Storage	Ternary Pumped Storage	Frame Turbine	Aeroderivative Turbine	Reciprocating Engine
Energy Provision	Short term (hours)		Short to mid-term (days)		Resources are not energy limited (assuming fuel availability)		
Capacity	Capacity credit methodology has not been standardized. Regions tend to follow either an ELCC approach or duration-based determination. Puget Sound Energy awards only credits partial capacity for batteries		Capacity credit methodology has not been standardized. Regions tend to follow either an ELCC approach or duration-based determination. Puget Sound Energy grants full capacity to pumped storage		May be de-rated based on deliverability		
Load Shifting	Short term only, operational constraints due to degradation	Short term only	Short to medium term		None		
Duration of Storage	Limited - storage capacity leakage when idle	Minimal storage capacity leakage	Water can be stored until needed		Cannot store energy		
Locational Benefits	Suitable for placement at distribution feeder or household level		Geographical limitations		Large footprint and additional infrastructure required	Suitable for placement in load pockets, but requires additional infrastructure (e.g. interconnection and fuel access) to achieve these benefits	

Service Provision Matrix

Excellent	
Good	
Okay	
Poor	

Technology	Batteries		Pumped Storage		Simple Cycle Natural Gas		
Example Unit	Li-Ion	Vanadium Flow	Adjustable Speed Reversible Pumped Storage	Ternary Pumped Storage	Frame Turbine	Aeroderivative Turbine	Reciprocating Engine
VAR Control	Inverters can supply VAR control		Can provide during pumping and generating		Can be operated to provide reactive power and voltage control		
Inertia	Inverters can supply virtual inertia		Provides physical inertia				
Frequency Response	Inverter can elicit virtual frequency response		Physical inertia dampens instantaneous frequency deviations				
Regulation (seconds to minutes)	Very fast response and flexible capacity, but dependent on state of charge and battery capacity		Fast response, but dependent on state of charge and reservoir capacity	Fast response and flexible capacity, but dependent on state of charge and reservoir capacity	Less flexible but still relatively responsive, but dependent on the operating state of unit. Does not have flexible capacity	Fast response, but dependent on the operating state of unit. Does not have flexible capacity	
Load Following	Very fast ramp rates and flexible capacity, but dependent on state of charge and battery capacity		Fast ramp rates, but dependent on state of charge and reservoir capacity	Fast response and flexible capacity, but dependent on state of charge and reservoir capacity	Slower than other simple cycles, though still relatively responsive. Dependent on the operating state of unit. Does not have flexible capacity range	Fast ramp rate, but dependent on the operating state of unit. Does not have flexible capacity range	
Spin Reserves	Very fast response rate		Capacity limited by the need to stop when changing between modes	Expanded capacity due to rapid mode switching	Spinning reserve range is limited to generation mode only (does not have flexible capacity range)		
Non-Spin Reserves	Fast start		Fast start	Fast start and quick mode change	Fast start		
Environmental Goals	Can absorb and shift renewable supply				Does not work toward greenhouse gas goals		

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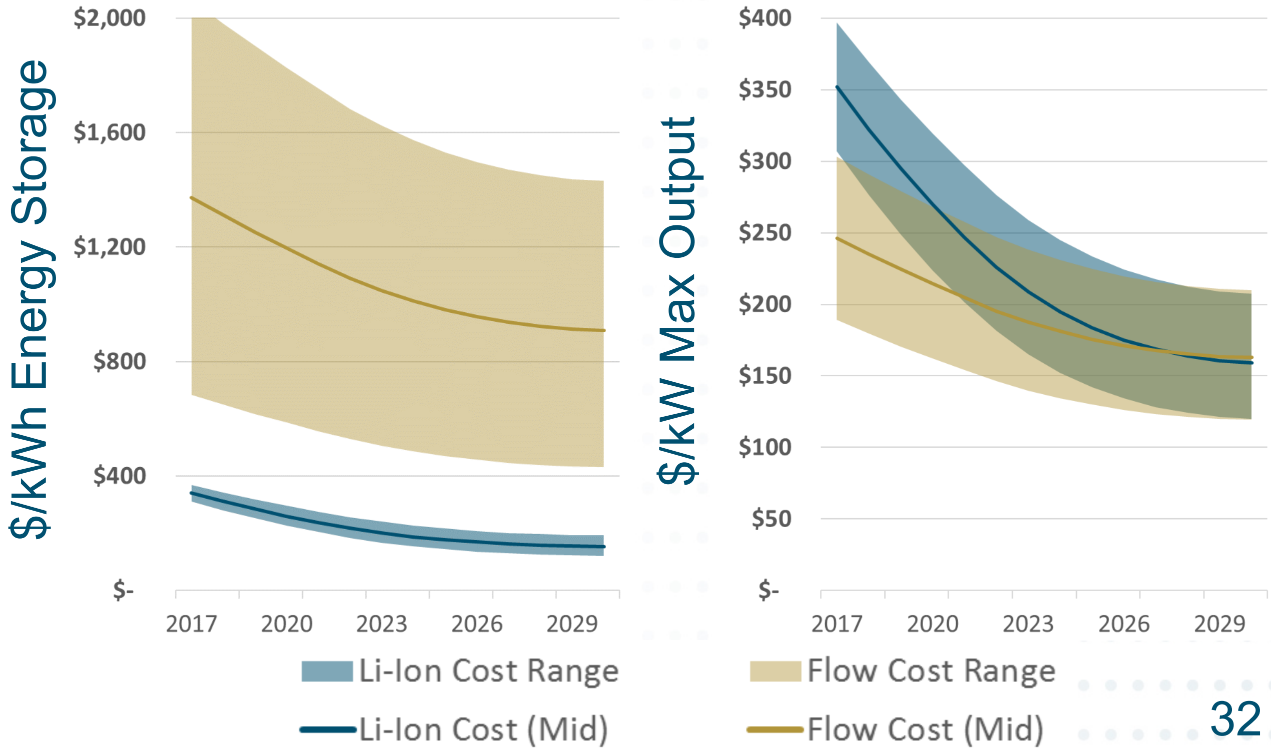
Appendix

Notes on Battery Cost

+ **Battery sizing can be broken into two components: Max Output (kW) and Storage Duration (hours)**
  - E3 breaks down costs into capacity (\$/kW) and energy (\$/kWh) costs

$$\textit{Total Battery Cost}\ (\$) = \left[\textit{Max Output} * \frac{\$}{kW}\right] + \left[\textit{Max Output kW} * \textit{hours} * \frac{\$}{kWh}\right]$$

+ **Flow batteries are expected to have higher capacity costs, while Li-Ion have higher energy costs**
+ **Li-Ion costs are expected to decline more by 2030**



Cost Assumptions

		Ternary Pumped Storage	Battery Storage (2020)*		Combustion Turbines		
Initial Value	Units	Absaroka Gordon Butte (PS)	Lithium-Ion	Flow	Aero	Frame	Reciprocating Engine
Capital - Capacity	$/kW	$2,438	$260	$1,196	$1,120	$817	$1,315
Capital - Energy	$/kWh	n/a	$269	$214	n/a	n/a	n/a
Capital - % One-Time	%	100%	13.0%	13.1%	100%	100%	100%
Fixed O&M - Capacity	$/kW-yr.	$13.00	n/a	n/a	$25	$7	$10
Fixed O&M - Energy	$/kWh	n/a	$5.38	$10.80	n/a	n/a	n/a
MACRS Term	years	20	7	7	20	20	20
Degradation	%	0%	4.0%	0%	0%	0%	0%
Useful Life	years	60	10	20	30	30	30

* Battery characteristics are based on the 2020 cost estimates for the "Peaker Replacement" use case described in the Lazard *Levelized Cost of Storage* analysis (see p. 8 of report)

Cost Analysis Data Sources

- **Combustion Turbine Specifications**
  - NWPCC Seventh Power Plan
    - Available at https://www.nwcouncil.org/energy/powerplan/7/plan/
- **Battery cost estimates and projections**
  - Lazard Levelized Cost of Storage v3
    - Available at https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf
  - Baseline results use 4-hr "Peaker Replacement" battery cost estimates
- **Battery lifetimes, capacity contributions**
  - Pacificorp 2017 IRP
    - Available at https://www.pacificorp.com/es/irp.html
  - Puget Sound Energy IRP
    - Available at https://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx
- **Conventional Pumped Hydro**
  - WECC Capital Cost Study (Update 2017)
    - Available at https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf
- **Gordon Butte Pumped Hydro**
  - Financial Data provided by Absaroka Energy

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Market Requirements

Market Analysis Matrix

Limited additional resources needed to meet service needs
Requires some additional resources to meet service needs
Requires substantial additional resources to meet service needs

<table>
<tr><th>Example Unit</th><th>System with significant amounts of behind-the-meter (BTM) solar</th><th>System with significant amounts of utility scale solar</th><th>System with significant amounts of utility scale wind</th><th>System with significant amounts of hydro</th><th>System with significant amounts of baseload generation</th></tr>
<tr><td>Energy Provision</td><td colspan="3" rowspan="2">Non-dispatchable resources may not be available when needed. Solar generation occurs only during daylight hours, and is largely uncontrollable.
Likewise, wind generation is less predictable than solar, but is possible at all hours</td><td>Seasonal differences in hydro availability may be expected. Dispatch may need to meet non-power needs (ex. environmental)</td><td>Baseload power is typically inflexible and run constantly</td></tr>
<tr><td>Capacity</td><td colspan="2">Dispatchable resources can contribute to resource adequacy needs</td></tr>
<tr><td>Load Shifting/Storage Duration Needs</td><td colspan="2">Storage can absorb excess energy during peak solar production hours of the day.</td><td>Short-term fluctuations can be managed by highly responsive storage, but storage may not be useful during long periods of low wind</td><td>Storage resources in a hydro-heavy system is inherently substantial - may preclude or reduce the need for further storage</td><td>This type of system could benefit from large storage systems to shift excess must-run supply to high load hours</td></tr>
</table>

Market Analysis Matrix

Limited additional resources needed to meet service needs
Requires some additional resources to meet service needs
Requires substantial additional resources to meet service needs

Example Unit	System with significant amounts of behind-the-meter (BTM) solar	System with significant amounts of utility scale solar	System with significant amounts of utility scale wind	System with significant amounts of hydro	System with significant amounts of baseload generation
Locational Issues	BTM solar, if sited properly, can reduce congestion on the distribution system	Large-scale resources are difficult to site in locations that reduce stress on transmission and distribution systems.			
VAR Control	Deviations may be more frequent due to lack of control and insight into BTM solar generation, leading to poorer forecast. Inertial mass from other resources will be necessary.	Forecast errors are still a concern, but utility scale solar is more easily curtailed than BTM solar. Inertial mass from other resources will be necessary.	Wind generation does not follow a basic daily pattern (as does solar), and its generation schedule is less predictable.	The dispatch of hydro resources is generally predictable and scheduled.	As baseload is inflexible, other resources must be able to follow load.
Frequency Response					
Regulation (seconds to minutes)					

Market Analysis Matrix

Limited additional resources needed to meet service needs
Requires some additional resources to meet service needs
Requires substantial additional resources to meet service needs

Example Unit	System with significant amounts of behind-the-meter (BTM) solar	System with significant amounts of utility scale solar	System with significant amounts of utility scale wind	System with significant amounts of hydro	System with significant amounts of baseload generation
Load Following/Ramping	Steep production ramps may be consistently needed during evening hours when increased load coincides with the setting of the sun		Short term fluctuations in the intermittent generation of wind energy will require flexible generation to follow the load	The dispatch of hydro resources is generally predictable and scheduled.	As baseload is inflexible, other resources must be able to follow load.
Spin/Non-Spin Reserves	Intermittent generation cannot contribute to spin/non-spin reserves – this void must be made up by other resources in the system			Nothing notable brought about by the characteristics of this system	
Environmental Goals	Contributes to greenhouse gas and RPS goals			Can contribute to greenhouse gas goals	Does not contribute to greenhouse gas goals

Attachment B

Ternary Pumped Storage Flexible Capacity Assessment

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Ternary Pumped Storage Flexible Capacity Assessment

Prepared for Absaroka Energy in response to NorthWestern Energy's 2015 Electricity Supply Resource Procurement Plan

5/8/2017

Arne Olson, Partner
Doug Allen, Managing Consultant
Vivian Li, Associate

Analysis Description

+ **Absaroka Energy LLC asked E3 to compare their ternary pumped storage technology to conventional resources in terms of their ability to provide "flexible capacity"**
  - Conventional resources considered: Internal Combustion (Reciprocating) Engine, Frame Combustion Turbine, Aeroderivative Combustion Turbine
+ **Flexible capacity does not have a specific definition, so we have looked at each resource's ability to provide**
  - System capacity
  - Ancillary Services

Flexible Capacity Cost Comparison

Nameplate Capacity	Frequency Response	Regulation Up/Down	Spinning Reserves	Non-spinning Reserves
Ability to provide capacity during peak events and contribute to required reserve margins	Most immediate response to deviations in grid frequency served by generator inertia	Provided by generators that are online and have capacity to increase or decrease generation output or load consumption (pumping)	Provided by units that are synchronized to the grid and, upon dispatch, able to ramp up within specified time frame	Provided by units that need not be synchronized to the grid, but are able to ramp up generation within specified time frame upon dispatch

Capital Cost Analysis
$\text{Product Specific Cost}\left(\frac{\$}{\text{kW}}\right) = \frac{\text{Capital Costs}^{*}\ (\frac{\$}{\text{kW}})}{\text{Product Specific Usable Capacity (\%)}}$

** Capital costs considered in this analysis include infrastructure costs as detailed in the 2015 NWE Electricity Supply Resource Procurement Plan*

Cost Comparison

- For each capacity product, we describe the ability of the different generating technologies to supply that product
- We then calculate the product-specific cost per kW by technology
  - Allows for more balanced comparison of "capacity cost" than a simple $/kW installed cost
- This comparison focuses on *costs per unit of flexible capacity only*, and does not include an analysis of potential revenues

Comparison Scope

+ **This analysis looks solely at the comparative capital costs (per installed kW) of the different technologies**
  - Accounts for each technology's ability to provide different capacity services
  - Does not account for
    - Fuel / Variable Operating costs
    - Revenues from participation in energy markets
    - Potential impacts of carbon price or air quality operating restrictions
    - Carbon benefits of absorbing renewable overgeneration for later use

Assumptions

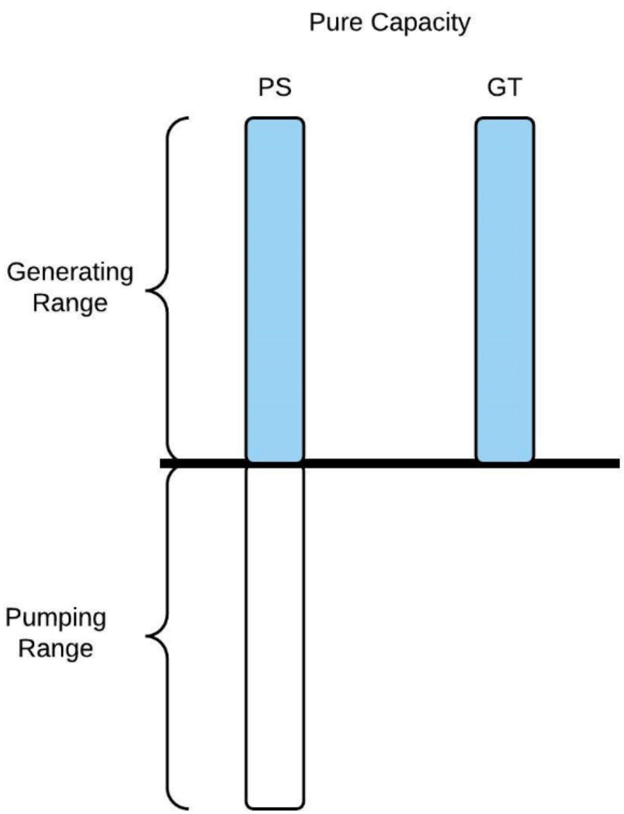
		Ternary Pumped Storage	Natural Gas Simple Cycle†		
Operating Characteristic	Units	Pumped Storage Hydro (PS)*	Internal Combustion Engine (ICE)	Aeroderivative Combustion Turbine (Aero)	Frame Combustion Turbine (Frame)
Technology	-	Ternary Unit	Warsila 18V50SG	GE LMS100	GE 7EA
Capacity	MW	150	18	93	79
Capital Costs◊	$/kW	$2,439	$1,756	$1,684	$1,459
Ramp Rate	MW/min	300	4	10	4
Start Time	min	0.4 – 1.5	not reported	not reported	not reported
Shut-down Time	min	2Δ	not reported	not reported	not reported
Min Run Time	Hours	not reported	1	8	8
Min Down Time	Hours	not reported	1	7	7
Operating Range	[min –max, as % of capacity]	-100% (pumping) – +100% (generating)	21%-100%	53%-100%	13%-100%

* *Data provided by Absaroka*
† *All Data taken from Thermal Resource Operating Parameters section of the NorthWestern Energy 2015 Electricity Supply Resource Procurement Plan*
Δ *Assuming "transfer mode" as the final state of rest*
◊ *Includes "Infrastructure" costs as described in NWE's Procurement Plan*

Nameplate Capacity

- Usable capacity provided by the unit (as listed in the NWE Procurement Plan)
- Reflects the unit's contribution to reserve margins / system capacity
- Amount of capacity available to meet peak capacity needs

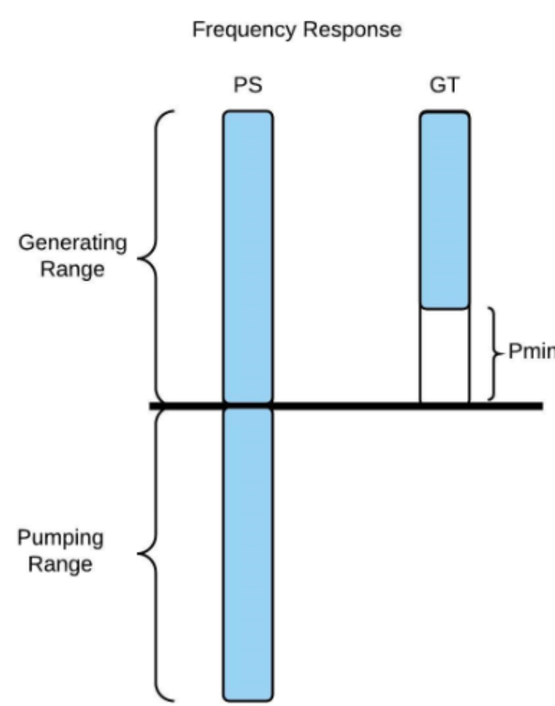
	Capacity Assumptions	Capital Costs (2018 $/kW)
PS	Generation rated power = 150 MW Pumping rated load = 150 MW	$2,439
ICE	Generation rated power = 18 MW	$1,756
Aero	Generation rated power = 93 MW	$1,684
Frame	Generation rated power = 79 MW	$1,459



Flexible Capacity: Frequency Response

- Primary control - most immediate response to deviations in grid frequency
- Served by generator inertia
- Provided primarily by frequency responsive loads and synchronous generators

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PS	• Inertia of turbine and generator provides frequency response • Some markets offer fast-frequency regulation products	200%	$1,220
ICE	• Primary response requirement for generators with governor function may exist • WECC specifies droop settings for conventional generators	79%	$2,223
Aero		47%	$3,583
Frame		87%	$1,677

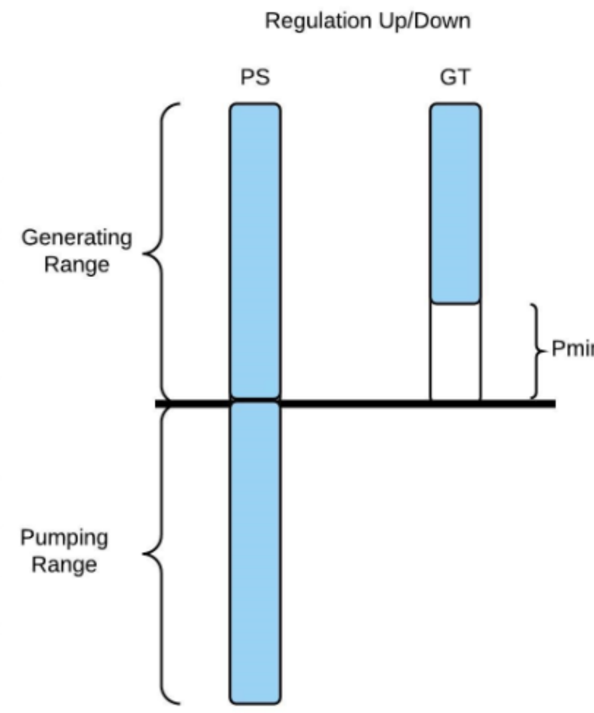


Assuming operating state is at optimal position for providing frequency response [ex. GT at Pmin]

Flexible Capacity: Regulation Up/Down

- Secondary control - occurs within seconds to minutes via automatic generation control
- Provided by generators who are online and have capacity to increase or decrease output

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PS	• Capacity to increase/decrease system output by reducing/increasing generation or load • Fast switching between modes doubles the effective range unit.	200%	$1,220
ICE	Capacity of conventional generators to provide regulation up and down is limited by ramp rate and minimum power generation levels.	79%	$2,223
Aero		47%	$3,583
Frame†		87%	$1,677



*Assuming operating state is at optimal position for providing frequency response [ex. GT at Pmin]
†Frame units are not usually used for Regulation given their limited operating flexibility

Spinning vs. Non-Spinning Reserves

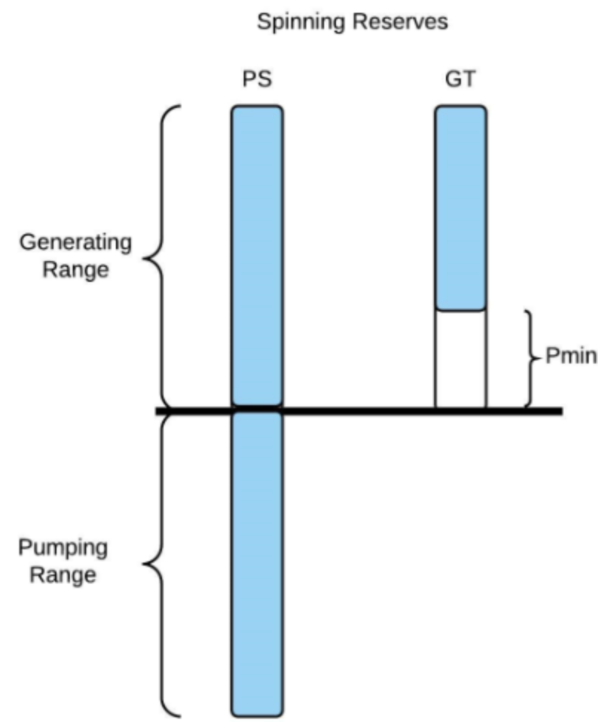
- Spinning/Non-spinning reserves are used to meet the same operating reserve obligation

- Fast response of ternary pumped storage units allows for provision of either spinning or non-spinning reserves, even when in charging mode

Flexible Capacity: Spinning Reserves

- Tertiary control - system operator dispatches reserves in response to contingencies
- Provided by units that are synchronized to the grid and able to ramp up within specified time frame

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PS	• Fast ramp rate and mode switching allows for fast response to operator dispatch • Unit in generation, idling, or pumping mode • Can increase/decrease load or generation • Can switch from one mode to another	200%	$1,220
ICE	• Limited by ramp rate, start-up times (hot-start)	79%	$2,223
Aero		47%	$3,583
Frame		87%	$1,677

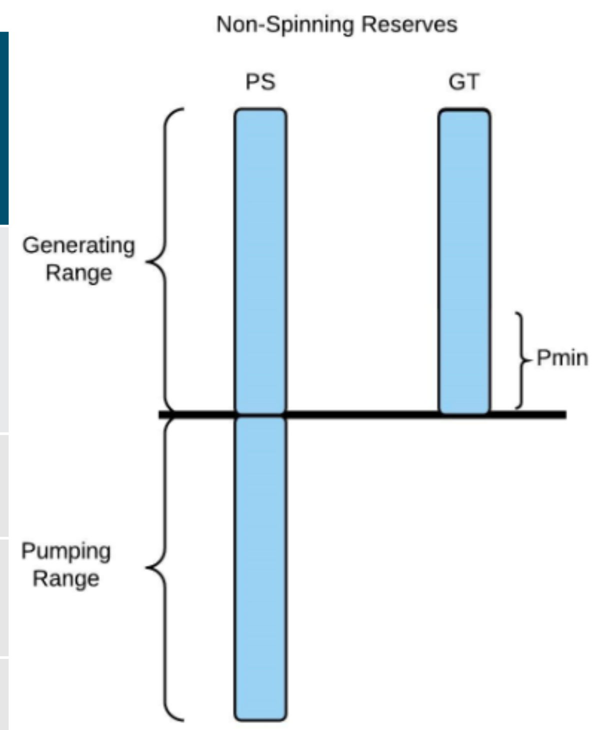


*Assuming operating state is at optimal position for providing frequency response [ex. PS pumping, GT at Pmin]

Flexible Capacity: Non-Spinning Reserves

- Tertiary control - system operator dispatches reserves in response to contingencies
- Provided by units that *are not necessarily* synchronized to the grid, but able to ramp up generation within specified time frame
- Required response time is slower than spinning reserves

	Capacity Assumptions	Usable Capacity Range (% of Nameplate)*	Capital Costs (2018 $/kW)
PS	• Unit in standby mode • If dispatched, can quickly ramp up capacity	200%	$1,220
ICE	• Capacity and participation limited by ramp rate, start up time (cold-start)	100%	$1,756
Aero		100%	$1,684
Frame		100%	$1,459



*Assuming operating state is at optimal position for providing frequency response [ex. PS pumping, GT not on]

Additional Flexible Capabilities

Operating Characteristic	Gordon Butte Pumped Storage Ternary Unit	Aeroderivative CT	Frame CT	ICE
Additional cost for each start	Minimal	Yes	Yes	Yes
Estimated median cold start cost*	n/a	$32/MW	$103/MW	Not provided
Can absorb overgeneration?	Yes	No	No	No
Black start?	Yes	Yes**	Yes**	Yes**

*Intertek APTECH (2012). Power Plant Cycling Costs. http://wind.nrel.gov/public/wwis/aptechfinalv2.pdf

**Siemens (2006). Black Start Studies. https://w3.usa.siemens.com/datapool/us/SmartGrid/docs/pti/2006June/Black_Start_Studies.pdf

Conclusions

- **Compared to the conventional resources described in NWE's 2015 IRP filing, Ternary Pumped Storage can provide the following services at a cheaper per-kW installed price:**
  - Frequency Response
  - Regulation Up / Down
  - Spinning Reserve
  - Non-Spinning Reserve
- **Beyond the ability to provide flexible and peak capacity considered here, this analysis does not reflect a pumped storage facility's ability to store energy for use later, which enables**
  - Absorption of overgeneration
  - Arbitrage of energy price spreads
  - Increased transmission system utilization

Attachment C

Gordon Butte Pumped Storage Colstrip 1&2 Replacement Analysis

Energy+Environmental Economics

Gordon Butte Pumped Storage

Colstrip 1&2 Replacement Analysis

Prepared by E3 for Absaroka Energy

December 2016

Analysis Overview

+ Absaroka Energy asked E3 to compare the cost of two alternatives for providing energy (250 aMW) and capacity (300 MW) to replace Puget Sound Energy's share of Colstrip 1&2

  • **MT Alternative:** Gordon Butte Pumped Storage facility paired with 250 aMW of Montana wind (located at Martinsdale, MT) and 300 MW of existing long-term firm transmission rights from Montana to PSE

  • **PNW Alternative:** An Aeroderivative CT generator (located in Washington state) paired with 250 aMW of Washington wind (located at the Columbia Gorge)

Gordon Butte Overview

+ **Gordon Butte Pumped Storage Facility**
  - 400 MW pumping / generating capacity
  - Ternary units allow seamless transition between generating and pumping modes
  - 8.5 available hours of storage
  - 83% efficiency
  - Sited to allow access to transmission currently used to deliver power from Colstrip coal plants in Montana. Some of this transmission capacity will become available when Colstrip 1&2 are retired (no later than 2022).
  - FERC License issued December 14, 2016.

Analysis Scope

+ Quantified benefits of pumped storage

- Shaping of wind resource to maximize value, avoid curtailment, and increase transmission utilization
- Ability to provide firm capacity on demand (given available capacity)
- Emissions-free flexible resource helps with wind integration
- Time-based market arbitrage opportunities (given available capacity)

+ Potential benefits of pumped storage not considered here

- Ability to provide ancillary services (Load-following, Regulation, Spinning & Non-Spinning Reserves, Frequency Response)
- Sub-hourly energy dispatch savings
- Value derived from participation in the Energy Imbalance Market

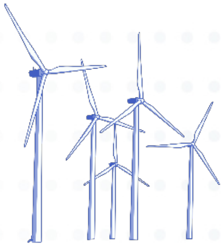
MT Alternative

Year = 2030

Dispatch value of energy provided to Puget Sound is determined by market prices at Mid-C

Washington

Montana



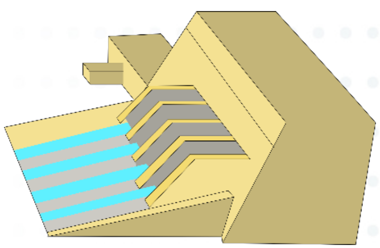
250 aMW Montana, CF ~46%

Puget Sound Energy

300 MW
(1.5% Losses)

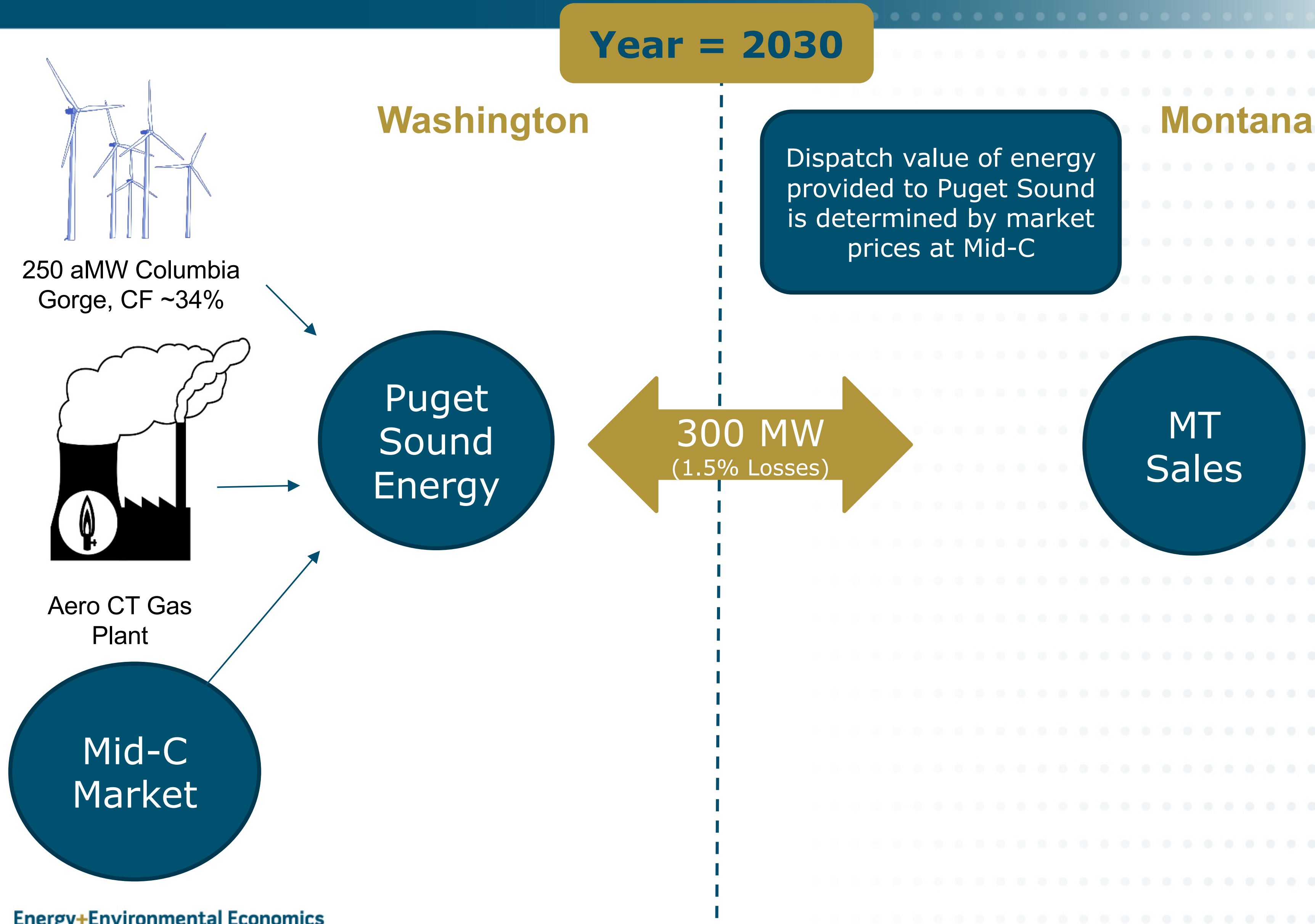
MT Sales

Mid-C Market



Gordon Butte Pumped Storage Facility

PNW Alternative



Wind Capacity Credit

+ Absaroka also asked E3 to investigate how geography-based differences in Effective Load Carrying Capability (ELCC) between wind sites might influence the results of the analysis
  - To achieve this, E3 sized both the pumped storage and Aero CT resources so that they provide 300 MW of capacity *when paired with the planning capacity assigned to wind resources*

Assumption	*WA Wind – Installed Capacity*	*WA Wind – Planning Capacity*	Aero CT Size	*MT Wind – Installed Capacity*	*MT Wind – Credited Capacity*	Pumped Storage Size
No Capacity Credit for Wind	*736 MW*	*0 MW*	**300 MW**	*548 MW*	*0 MW*	**300 MW**
Capacity Credit for Wind	*736 MW*	*37 MW (5%)*	**263 MW**	*548 MW*	*137 MW (25%)*	**163 MW**

Modeling Efforts

- Fixed costs for the resources were calculated using E3 financial models and publicly available data sources
- Hourly dispatch values were calculated using an adapted version of the E3 REFLEX model
  - REFLEX is a multi-stage production simulation model with integer variables formulated for high renewable penetrations
    - Hourly modeling of energy values and arbitrage opportunities
    - Hourly generation profiles for non-dispatchable (wind) generation
    - Priced-based dispatch of controllable resources
    - 24-hour optimization of storage resources

Data Sources – Wind Resource Characteristics

+ **Wind shapes provided by Absaroka Energy**
  - E3 adjusted to reflect most recent capacity factors
    - Washington (Columbia Gorge): 34% Capacity Factor
    - Montana (Martinsdale, MT): 46% Capacity Factor
  - Nameplate capacity sized to output 250 aMW over the course of the year
    - Columbia Gorge: 736 MW
    - Martinsdale: 548 MW
+ **Wind planning capacity based on location of wind resources**
  - Reasonable estimates based on previous E3 analysis
    - Washington (Columbia Gorge): 5% Capacity Value
    - Montana (Martinsdale, MT): 25% Capacity Value

Data Sources – Other Resource Characteristics

- **Aero CT characteristics based on generators in the TEPPC Common Case**
- **Pumped storage operational characteristics provided by Absaroka Energy** (see previous slide)
- **Transmission losses of 1.5% Montana to BPA**
  - Based on Colstrip Transmission System losses from Broadview to Garrison

Data Sources – Cost / Pricing Characteristics

- Wind capital costs based on NREL data
- Aero CT capital costs taken from Northwest Power and Conservation Council's 7th Power Plan
- Gordon Butte Pumped Hydro capital costs from Absaroka Energy
- 2030 gas prices based on Henry Hub forwards and basis spreads
  - 2030 chosen to represent "typical" future gas and power market conditions
- Cost of existing firm transmission rights treated as a sunk cost

Key Financial Assumptions

Metric	Assumption	Source
MT Wind LCOE	40 $/MWh	NREL capital costs, 46% CF, 2018 commencement (for PTC)
WA Wind LCOE	65 $/MWh	NREL capital costs, 34% CF, 2018 commencement (for PTC)
CT Levelized Fixed Cost	192 $/kW-yr.	NWPCC 7th power plan, Aero GT East**
Gordon Butte Levelized Fixed Cost	350 $/kW-yr.	E3 estimate based on GBEP Financial Model
Mid-C Prices	Vary by Hour	E3 projection for 2030 based on historical price patterns, resource mix, and gas price projection
MT Price Discount, Hours with Constrained Tx	6.9 $/MWh	Discount (buying and selling) during hours when wind exceeds capacity of 300 MW of existing firm transmission to deliver to PSE (approximates cost to wheel from MT to Mid-C on hourly nonfirm transmission)
Discount Rate	10%	Taken from GBEP Financial Model

* http://www.brattle.com/system/publications/pdfs/000/004/827/original/Resource_Adequacy_in_California_Calpine_Pfeifenberger_Spees_Newell_Oct_2012.pdf?1378772133
**https://www.nwcouncil.org/media/7149910/7thplanfinal_appdixh_gresources.pdf

Results – With Wind Capacity Value

- **MT Alternative provides substantial benefits to PSE ratepayers:**
  - **$300 million** reduction in capital costs
  - **$53 million** reduction in levelized annual costs
    - **$481 million** NPV over 25 years
  - **$24/MWh** reduction in levelized energy costs (250 aMW)

Results – Wind Provides Planning Capacity

	P-PNW	P-MT	
GENERATION SUMMARY			
Wind Energy (aMW)	**250**	**250**	
Wind Capacity (Nameplate MW)	**736**	**548**	
Wind Planning Capacity (MW)	**37**	**137**	
Aero CT Capacity (ME)	**263**	**-**	
Pumped Hydro Capacity (MW)	**-**	**163**	

	P-PNW	P-MT	MT BENEFITS
CAPITAL COSTS ($MILLIONS)			
Wind	$ 1,472	$ 1,096	
Aero CT	$ 290		
Pumped Hydro		$ 367	
Total	$ 1,622	$ 1,463	**$ 299**
	P-PNW	**P-MT**	**MT BENEFITS**
LEVELIZED FIXED COSTS ($millions)			
250 avg. MW Wind	$ 208	$ 153	
300 MW CT Capacity	$ 50	-	
300 MW Pumped Storage Capacity	-	$ 57	
Total	$ 258	$ 210	$ 48
ANNUAL DISPATCH VALUE ($millions)	$ 44	$ 49	$ 5
TOTAL ANNUAL BENEFITS ($millions)			**$ 53**
25-YEAR NPV BENEFITS ($millions)			**$ 481**
ENERGY COST BENEFIT ($/MWh)			**$24/MWh**

Results – Without Wind Capacity Value

- **Even ignoring the superior capacity value of MT wind, the MT Alternative provides significant benefits to PSE ratepayers:**
  - **$31 million** reduction in capital costs
  - **$18 million** reduction in levelized annual costs
    - **$163 million** NPV over 25 years
  - **$8/MWh** reduction in levelized energy costs (250 aMW)

Results – No Wind Planning Capacity

	P-PNW	P-MT	
GENERATION SUMMARY			
Wind Energy (aMW)	**250**	**250**	
Wind Capacity (Nameplate MW)	**736**	**548**	
Wind Planning Capacity (MW)	**0**	**0**	
Aero CT Capacity (ME)	**300**	**-**	
Pumped Hydro Capacity (MW)	**-**	**300**	

	P-PNW	P-MT	MT BENEFITS
CAPITAL COSTS ($MILLIONS)			
Wind	$ 1,472	$ 1,096	
Aero CT	$ 330		
Pumped Hydro		$ 675	
Total	$ 1,802	$ 1,771	**$ 31**
	P-PNW	**P-MT**	**MT BENEFITS**
LEVELIZED FIXED COSTS ($millions)			
250 avg. MW Wind	$ 208	$ 153	
300 MW CT Capacity	$ 57	-	
300 MW Pumped Storage Capacity	-	$ 105	
Total	$ 265	$ 258	$ 7
ANNUAL DISPATCH VALUE ($millions)	$ 44	$ 55	$ 11
TOTAL ANNUAL BENEFITS ($millions)			**$ 18**
25-YEAR NPV BENEFITS ($millions)			**$ 163**
ENERGY COST BENEFIT ($/MWh)			**$8/MWh**

Energy+Environmental Economics

Thank You!

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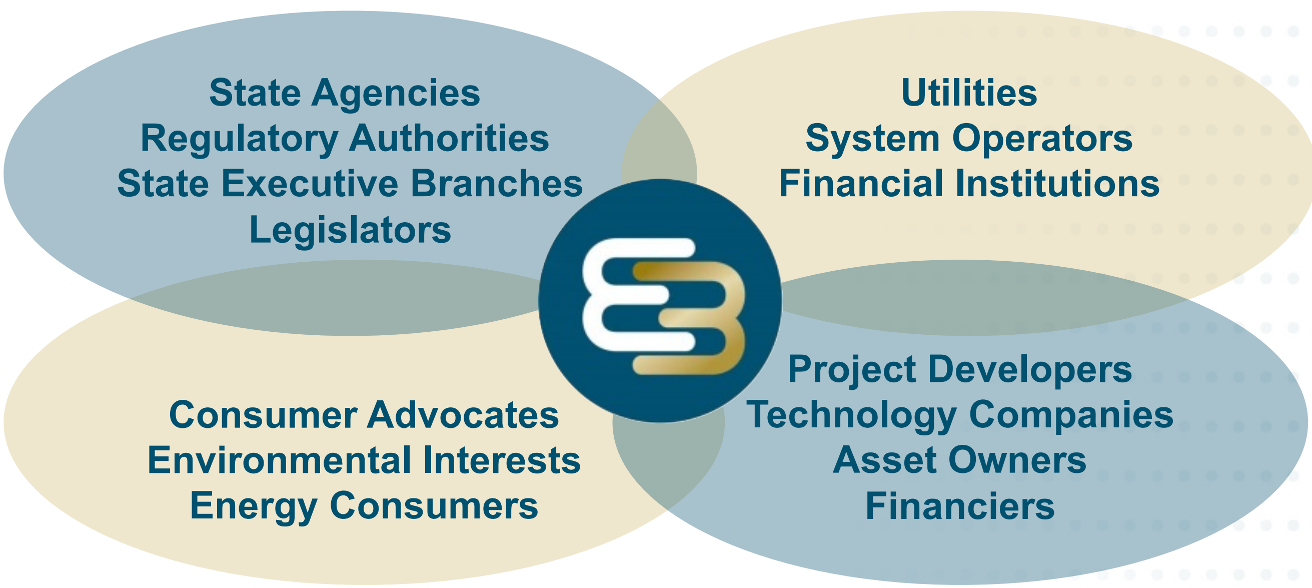
About E3

- Founded in 1989, E3 is an industry leading consultancy in North America with a growing international presence
- E3 operates at the nexus of energy, environment, and economics
- Our team employs a unique combination of economic analysis, modeling acumen, and deep institutional insight to solve complex problems for a diverse client base



Asset Valuation Overview

- E3 relies on the following key strengths to provide industry-leading consulting for asset valuation services

Reputation for high quality

Objectivity and transparency

Experience and integrity

Industry leading knowledge

- The Asset Valuation Group focuses on short and longer-term valuation analysis that provides unique insights for the following:

Traditional Bulk System Assets

Generation Assets
Renewable & Traditional
(Bulk and Distribution Level)

Energy Storage Assets
(Bulk and Distribution Level)

Pipeline Assets