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December 4, 2017

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Filing Center
Public Utility Commission of Oregon
201 High Street, SE Ste. 100
Salem, OR 97301

RE: UM _____ – Portland General Electric Resource Value of Solar Filing

Attention Filing Center:

Per direction given in Order No. 17-357 of Docket No. UM 1716, Portland General Electric hereby submits its Resource Value of Solar filing and accompanying testimony. Electronic workpapers and calculations associated with this filing will be posted to Huddle. Enclosed for filing in the above referenced matter please find the following:

- **Direct testimony of Jacob Goodspeed (PGE/100)**
- **Direct testimony of Tess Jordan (PGE/200)**
- **Direct testimony of Brett Sims (PGE/300)**
    - **PGE/301 – "How Big is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest"**
- **Direct testimony of Darren Murtaugh (PGE/400)**
    - **PGE/401 – Marginal Cost Study Results from Docket No. UE 319**
    - **PGE/402 – Bonneville Power Administration 2018 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2018-2019**
    - **PGE/403 – PGE's Draft Storage Potential Evaluation**
- **Direct testimony of Brad Carpenter (PGE/500)**
    - **PGE/501 – "Spring 2016 National Carbon Dioxide Price Forecast"**

If you have any questions, please contact Jacob Goodspeed at (503) 464-7806. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Karla Wenzel

Karla Wenzel
Manager, Pricing

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I. Introduction

Q. Please state your name and position with Portland General Electric (PGE).

A. My name is Jacob Goodspeed. I am a senior analyst in Pricing and Tariffs for PGE. My qualifications appear in Section VI of this testimony.

Q. What is the purpose of your testimony?

A. My testimony is designed to respond to Order No. 17-357 in Docket No. UM 1716 – Investigation into the Resource Value of Solar (RVOS). Specifically, I will address the following:

1. Summary of results for each RVOS element;
2. Comparison of PGE's RVOS results compared to a utility-scale proxy;
3. Introduction of the integration value and discussion of the methodology used to calculate the integration value; and
4. Introduction of the administration value and a discussion of the methodology used to calculate the administration value.

Q. Please provide context for your testimony and for the values being proposed by PGE.

A. PGE is proposing element values in compliance with Order No. 17-357. UM 1716 was opened in early 2015 following a Public Utility Commission of Oregon (Commission) report to the legislature pursuant to House Bill (HB) 2893 (2013 legislative session), regarding the effectiveness of solar programs in Oregon. Throughout 2015, Staff and Stakeholders worked collaboratively to determine the elements that should be included in the RVOS. In September 2015, Staff recommended that the Commission provide guidance on which of the 26 proposed elements should be examined in determining the RVOS. In addition, Staff recommended the hiring of a consultant to assess and develop methods to quantify the selected elements. Staff hired Energy and Environmental Economics (E3) to support the modeling and calculation of the RVOS element stack in UM 1716.

Q. Please provide a brief summary describing how the elements were selected in UM 1716.

A. Staff conducted a robust public stakeholder process in UM 1716 that was designed to determine how to accurately value the RVOS. A total of twenty-six elements were originally proposed by the stakeholders for inclusion, and these proposed elements encompassed a wide variety of perceived costs and benefits of distributed solar.

Commission Order No. 15-296 directed that the Commission would only consider elements that impact the cost of service to utility customers. For example, the Commission stated it would consider the cost of carbon regulation to utilities, but would not consider the economic development (jobs) impacts of solar development.[1] In accordance with Order 15-296, Staff proposed a set of ten elements that were deemed to directly impact the cost of service to utility customers. These ten elements, plus a placeholder for the future value of grid services, are the elements calculated by PGE in this filing.

Q. Is there indication of how the RVOS will be used once a price is determined?

A. Yes. A specific application for the RVOS has been identified for community solar and was specified in the 2016 legislation, SB 1547. Additionally, in Docket No. UM 1758 "Solar Incentives Report" from the Commission to the Oregon Legislature, the Commission stated that the RVOS "should also be used for net metering.… We will open a docket on examining the integration of the RVOS for net metering."[2]

[1] Order No. 15-296
[2] UM 1758 Solar Incentive Report to Legislature, page 3, sent November 1, 2016.

Q. Staff's consultant, E3, produced a model for the purposes of calculating the RVOS. Did PGE use this model?

A. Yes. PGE has filed two versions of this model, included with this filing as workpapers. The RVOS distributed workbook contains the calculated element values based on the methodology outlined on pages 21-23 of Order No. 17-357. The RVOS utility-scale proxy workbook contains a separate E3 workbook with an RVOS assuming a utility scale solar proxy. The production of a model showing estimated utility scale proxy amounts is in accordance with Order No. 17-357.

II. Summary of Results

Q. Has PGE calculated a value for each of the 11 elements listed in Order No. 17-357?

A. No. PGE has produced values for: Energy, Generation Capacity, Transmission and Distribution (T&D) Capacity, Line Losses, Administration, Integration, Market Price Response, and Environmental Compliance. Per Commission Order, PGE used 5% as the value for the Avoided Cost of Hedging.[3] Per Order No. 17-357, PGE has not provided values for Renewable Portfolio Standard (RPS) Compliance or Grid Services elements, as additional process will be initiated to value those elements.[4] We look forward to participating in the RPS Compliance and Grid Services workgroups once they are scheduled.

Q. In PGE's understanding, is each element identified for inclusion in the RVOS intended to be applicable to every project sited in the State of Oregon?

A. Not necessarily. It is PGE's understanding – based on Staff Witness Olson's testimony in Staff/200, Olson/4 – that the RVOS is intended to represent a locational, marginal, temporal price for the unique costs and benefits of a solar generator. Thus, different projects with different geographic attributes, sizes, or temporal characteristics may see different total RVOS prices.

Q. Please provide a summary of the elements for which PGE has produced values and the methodology underlying the proposed values.

A. Figure 1 below shows the RVOS element, definition, methodology used for calculation by PGE, and identifies the written testimony in which additional detail may be found. PGE has calculated values for the following elements:

[3] Order No. 17-357, pg 12
[4] Order No. 17-357 pg 15

Figure 1
Calculated RVOS Elements

RVOS Element	Definition	Methodology	Additional Detail
Energy	The marginal avoided cost of procuring or producing energy, including fuel, operation and maintenance (O&M) costs, pipeline costs, and all other variable costs.	12 x 24 block for energy prices, scaled to represent the average price under a range of hydro conditions.	PGE/200
Generation Capacity	The marginal avoided cost of building and maintaining the lowest net cost generation capacity resource.	Value determined to be consistent with current standard nonrenewable Qualified Facilities (QF) avoided cost guidelines. During the deficiency period, the value is based on the contribution to peak of solar photovoltaic (PV), multiplied by the cost of PGE's avoided proxy resource.	PGE/200
T&D Capacity	Avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure.	System-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration.	PGE/400
Line Losses	Avoided marginal electricity losses from the point of generation to the point of delivery.	Incremental line loss estimates based on seasonal and high loading/low loading scenarios.	PGE/400
Administration	Increased utility costs of administering solar PV programs.	Estimate of the direct, incremental costs of administering solar PV programs including staff, software, incremental distribution investments, and other utility costs.	PGE/100

RVOS Element	Definition	Methodology	Additional Detail
Market Price Response	The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production.	Estimate of the change to PGE's portfolio costs based on solar penetration in the wholesale market.	PGE/300
RPS Compliance	To be determined	Not calculated at this time	PGE/500
Integration	The costs of a utility holding additional reserves in order to accommodate unforeseen fluctuations in system net loads due to addition of renewable energy resources.	Estimate of integration based on acknowledged integration study from PGE's 2016 Integrated Resource Plan (IRP).	PGE/100
Hedge Value	Avoided cost of utility hedging activities (i.e., transactions intended solely to provide a more stable retail price over time).	A proxy value of 5% is assigned, per Commission Order No. 17-357.	PGE/300
Environmental Compliance	Avoided cost of complying with existing and anticipated environmental standards.	Estimated avoided cost of compliance based on a reduction in carbon emissions from the marginal generating unit. Carbon assumptions consistent with PGE's 2016 IRP.	PGE/500
Grid Services	The potential benefits of solar PV in advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters.	Not calculated at this time.	

Q. Please summarize the real levelized values on a per MWh basis for each of the elements that PGE has calculated.

A. Figure 2 below provides a real levelized summary of PGE's RVOS element values:

Figure 2 – RVOS values by element

RVOS Element	2017 $/MWh, real levelized value
Energy	24.98
Generation Capacity	7.30
T&D Capacity	8.08
Line Loss	1.48
Administration	(5.58)
Market Price Response	1.81
Integration	(0.83)
Hedge Value	1.25
Environmental Compliance	11.41
RPS Compliance	0
Grid Services	0
RVOS Total	**49.88**

*totals may not tie due to rounding

Q. Does PGE anticipate additional modifications to the total RVOS price during this docket?

A. Yes. PGE's understanding is that a value may be added for RPS compliance. A value may also be added in the future for grid services, but that may occur after the completion of this docket.

Q. PGE has previously advocated for the ability to update the RVOS on an annual basis. Does PGE continue to advocate for this approach?

A. Yes. With a complex, multi-element calculation such as the RVOS, having the most up-to-date element values possible will ensure that PGE customers are compensating solar at the correct price. Further, as stated in Staff/100, the RVOS is meant to be a marginal, locational, and temporal price.[5] Ensuring frequent opportunity to update would ensure that these three stated goals are met and are as accurate as possible.

[5] Staff/100, page 24

III. Comparison with Utility Scale Proxy

Q. Please detail PGE's understanding of why the value of a utility scale solar proxy is included in the initial calculation of RVOS elements.

A. PGE included a utility scale proxy estimate in compliance with Order No. 17-357, which states:

> "As a reference point only, the utilities should provide a separate E3 workbook with an RVOS assuming a utility scale proxy… The utility scale proxy is not a cap on RVOS, it is only a reference point to advance understanding of evaluation methods as we work through Phase II."

PGE has prepared PGE/102, which provides a separate E3 workbook with an element value stack based on inputs replaced with PGE's current renewable avoided cost (Schedule 201).

Q. Why did PGE populate the utility-scale proxy workbook with values from PGE's renewable avoided cost?

A. PGE has provided renewable avoided cost as the inputs in accordance with Order No. 17-357, which directs utilities to "provide a separate E3 workbook with a RVOS assuming a utility scale solar proxy to replace all elements but T&D capacity, administration, and line losses."[6] The workbook includes PGE's current values for these elements, based on the avoided cost of building a proxy renewable resource.

RVOS is inherently a compensation price based on a set of discrete values and costs associated with a specific resource type. Solar is not currently PGE's proxy resource, nor has it been. PGE has not previously constructed a utility-scale (defined in the 2016 IRP as

[6] Order No. 17-357, page 18

50-200MW) solar resource. Thus, PGE does not have readily available values for the benefit stream associated with an avoided utility-scale solar resource.

Q. Is the Schedule 201 renewable avoided cost data useful for comparison in this docket?

A. Yes. Although not based specifically on a solar resource – as PGE's proxy resource is wind, not solar – the values contained in Schedule 201 provide data on what the avoided cost would be for PGE's lowest-cost renewable proxy. It is the most relevant data that PGE has in the absence of a solar study specifically for use in this docket. It provides a comparison between what it would cost the utility to build the renewable and the proposed compensation for distributed (including community) solar generation.

Q. Although element-specific values may not currently be present for a solar proxy resource, does PGE have a high-level estimate of what utility-scale solar may cost?

A. Yes. PGE has previously received cost estimates from consultants regarding the cost of utility-scale solar. The most recent production cost estimates that PGE has for utility-scale solar were provided in 2016, and are estimated to be approximately $62/MWh. However, this estimate was intended only as an estimate and the values may have changed in the time since the study was conducted.

Q. Are the assumptions in the utility-scale case consistent with PGE's IRP?

A. Yes. Calculation of PGE's utility-scale proxy RVOS is in accordance with the 2016 IRP as follows:

1. An effective load carrying capacity (ELCC) value of 15.33% was used to calculate capacity contribution. This is consistent with the 2016 IRP's assumptions, and is used to calculate both the quantity of generic annual capacity resources needed to achieve a specific reliability target and to determine the

marginal capacity contribution value of incremental wind and solar resources. The current value of 15.33% includes solar resources on PGE's system and for executed QF contracts.

2. The integration cost of the utility-scale renewable proxy is consistent with Section 7.2.1.1 of PGE's IRP.

3. The average solar capacity factor used for the "solar shape" in the E3 model is consistent with the average capacity factor used in the IRP.

4. All financial assumptions – inflation rate, discount rate, etc. – are consistent with IRP values.

IV. Integration

Q. Did the Commission provide specific instruction regarding how to calculate a value for the integration element?

A. Yes. Order No. 17-357 states: "[we] retain the straw proposal methodology whereby the utilities will use inputs for integration costs based on acknowledged integration studies."

Q. Has PGE calculated a value for this element?

A. Yes. Section 7.2.1.1-7.2.1.2 of PGE's 2016 IRP details the methodology behind the calculation of the variable integration value. It is based on acknowledged integration studies. The estimated variable integration value, in 2016 dollars, is $0.83/MWh.

V. Administration

Q. Has the Commission provided specific guidance regarding how to calculate a value for the administration element?

A. Yes. Order No. 17-357 states:

> "[T]he administration element is only intended to capture costs that are both incremental to what the utility incurs for any other customer account and incremental to any portion of the cost paid by the interconnecting solar generator."

Q. Has PGE calculated a value for the administration element?

A. Yes. We estimate the value to be $5.58 per MWh. Workpapers associated with this calculation are included in the filing.

Q. What does this cost include?

A. The cost associated with this element includes PGE's Customer Interconnection group (which handles net metering inquiries and interactions) and PGE's Specialized Billing group. Specialized billing was limited only to their 2018 budget for net metering activities.

Q. Is this cost inclusive of community solar administration?

A. Not at this time. Oregon's Community Solar Program is currently undergoing a public bid for a program administrator. Under Oregon state law, the startup costs for this administrator are recoverable through utility rates. PGE has currently not received any cost information for the program administrator, and PGE has not received an indication from Staff regarding the preferred method of recovery through utility rates. Additionally, the ongoing cost of community solar administration may be recovered through the administration element of the RVOS but it is not included here as the program has yet to be implemented.

VI. Qualifications

Q. Mr. Goodspeed, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Public Policy from Washington State University and a Master of Business Administration degree from the University of New Orleans. I accepted my current role at PGE in 2016, and have previously worked in Senior Pricing Analyst and Pricing Lead roles for Entergy Services, Inc., providing pricing and rate design support to Entergy Louisiana LLC., Entergy Texas Inc., Entergy New Orleans Inc., and Entergy Arkansas Inc. I have also served as a financial analyst in Entergy's nuclear organization.

Q. Does this conclude your testimony?

A. Yes.

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I. Introduction

Q. Please state your name and position with Portland General Electric ("PGE").

A. My name is Tess Jordan. I am a senior analyst in Financial Forecasting and Economic Analysis for PGE. My qualifications appear in Section IV of this testimony.

Q. What is the purpose of your testimony?

A. My testimony responds to the Public Utility Commission of Oregon (Commission) Order No. 17-357 in Docket No. UM 1716, which directs utilities to file proposed Resource Value of Solar (RVOS) values for each element identified in the order. Specifically, I address:

- Capacity value – Methodology based upon PGE's current approved standard avoided cost, with description of how these values were calculated.
- Energy value – Calculated as a 12 x 24 block for energy prices, along with a narrative description of how these values were calculated and how they are representative of the average price under a range of hydro conditions.

Q. Did the Commission provide specific instructions regarding how to calculate the avoided cost of capacity?

A. Yes. In Order No. 17-357, the Commission directed utilities to provide "capacity value and timing (deficiency date) in line with their current approved standard nonrenewable Qualified Facilities (QF) avoided cost capacity value."[1] During the deficiency period, the utility should multiply the contribution to peak of the resource type by the capacity cost of the utility's avoided proxy resource.

[1] Order No. 17-357, pg. 6

In addition, the Commission directed Commission Staff to convene a workshop at a future date to determine the following capacity valuation topics:

1. Allowing the full capacity value up to a reasonable number of years before the deficiency year (e.g., three or four years) as recognition that it takes several years to ramp up infrastructure to avoid a major resource.
2. Using the short-run marginal cost of fixed operations and maintenance (O&M) as a proxy value as suggested by Energy and Environmental Economics (E3);
3. Other ideas arising from related Commission dockets or those raised by parties.

Q. Did the Commission give specific instruction on how to value the avoided cost of energy?

A. Yes. Order No. 17-357 specified that

> "Utilities shall produce a 12 x 24 block for energy prices and include a detailed explanation of how they created the block. Utilities shall demonstrate through statistical analysis that their energy values are scaled to represent the average price under a range of hydro conditions."[2]

[2] Order No. 17-357, pg 21

II. Capacity Value

Q. Please explain how "sufficiency" and "deficiency" apply to the calculation of capacity value.

A. For PGE's Tariffed Schedule 201 "Standard Non-Renewable Avoided Cost" rates, the Commission determined that PGE's sufficiency period for capacity resources extends through 2020. Given that the utility is capacity sufficient during the sufficiency period, no value is assigned to capacity. For the deficiency period, beginning in 2021, avoided cost pricing includes the capacity value of incremental resources. For solar, the capacity value is then adjusted for the capacity contribution of solar. This value and its underlying methodology is the basis for the avoided capacity RVOS element. Workpapers detailing this calculation have been included with this filing.

Q. Does PGE advocate for sufficiency/deficiency periods in the RVOS?

A. Yes. As stated by PGE witnesses Jacob Goodspeed and Darren Murtaugh during the January 31, 2017 hearing in Docket No. UM 1716, PGE advocates for keeping sufficiency and deficiency demarcations in the resource value of solar price consistent with PGE's Schedule 201.

Q. Please provide background and context regarding how PGE calculates the value of capacity for use in its standard avoided cost for Qualifying Facilities, Schedule 201.

A. PGE uses a simple cycle combustion turbine (SCCT) as the proxy capacity resource. The levelized, fixed costs of this proxy asset align with cost assumptions in PGE's 2016 Integrated Resource Plan (IRP): $125.86/kW-year in 2020 dollars, with an in-service year of 2021.

In Schedule 201, during the deficiency period, the capacity contribution of solar resources (per the IRP) is multiplied by the cost of PGE's avoided proxy resource. The resulting value is then spread across the number of peak hours per year, adjusted for the proxy solar resource's peak capacity factor. No capacity payment is assigned to non-peak hours. The model produces one capacity payment (in dollars per MWh) per year for all peak hours (with no seasonal shaping). Peak hours are Monday through Saturday, 6 am – 10 pm.

Q. What is the solar resource capacity contribution used in PGE's Schedule 201?

A. The current capacity contribution of solar resources used in PGE's Schedule 201 is 15.33%.

Q. Does PGE propose to use the same capacity contribution value in RVOS calculations?

A. Yes.

Q. How does PGE calculate the solar capacity contribution?

A. PGE calculated the capacity contribution of incremental additions of solar and wind resources in its 2016 IRP.[3] The capacity contribution, or effective load carrying capacity, (ELCC) values were calculated using Renewable Energy Capacity Planning Model (RECAP).

RECAP is a publicly available comprehensive loss of load probability (LOLP) model created by E3. The model is described in Section 5.1 of PGE's 2016 IRP. PGE used the model to calculate both the quantity of generic annual capacity resources needed to achieve a specific reliability target and to determine the marginal ELCC value of incremental wind and solar resources.[4] The model added resources in 100 MW increments and determined the ELCC value for each incremental 100 MW "bin". The ELCC value represents the quantity

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[3] See PGE's 2016 IRP, Section 5.1.5.
[4] The incremental solar resource modeled was single-axis tracking PV located in Central Oregon.

of generic capacity resources that can be avoided while achieving the same reliability target given the addition of the specified incremental resource (wind or solar).[5]

The current Schedule 201 solar ELCC value of 15.33% corresponds to the incremental solar resource bin of 200-300 MW.[6] This accounts for solar resources on PGE's system and for executed solar QF contracts.

Q. Does the RVOS capacity payment (in dollars per MWh) differ from the Schedule 201 capacity payment for solar resources?

A. Yes. The dollars per MWh number in RVOS differs from the Schedule 201 capacity payment for solar resources in that it applies a (lower) flat payment to be applied over all hours. PGE's standard avoided cost methodology assigns capacity payments to on-peak hours only. The E3 model provided in Staff/100 is constructed with an hourly (8760) and annual framework, resulting in a flat capacity payment rather than the 12 x 2 format currently used for standard avoided cost.

PGE's RVOS capacity payment reflects the capacity factor utilized in Schedule 201, to align with avoided cost pricing, and to provide consistency between capacity factor and the ELCC value of 15.33% (based on an Eastern Oregon resource with 24.4% capacity factor). These values can be further refined by tailoring both the ELCC and the capacity factor employed in the model to reflect the resources to which RVOS will be applied.

Q. Does PGE recommend any further changes to E3's model to increase accuracy?

A. Yes. PGE suggests providing more granular capacity pricing. Currently, capacity payments are equally spread across all peak hours in which the solar resource generates energy.

[5] See PGE's 2016 IRP, Section 5.1.5.
[6] The third column in Solar Marginal ELCC shown in Figure 5-11 of the 2016 IRP.

However, this sends inaccurate signals of when a resource contributes to reducing PGE's capacity needs; for example, it values 8 a.m. in May equally to 5 p.m. in August. Figure 5-3 of the 2016 IRP indicates that capacity shortages cluster in winter morning and evening hours, and in the summer afternoon and evening hours. PGE recommends that solar capacity pricing be calculated as 12x16 peak blocks that incorporate both the seasonal and hourly generation profile of solar and the seasonal and hourly profile of capacity need.

Q. Order No. 17-357 instructs utilities to remove incremental distributed solar photovoltaic from the load forecast for their initial RVOS filing. Has PGE made this modification?

A. No. PGE does not make any explicit assumptions about incremental distributed solar photovoltaic (PV) as part of the load forecasting process. The impact of existing distributed solar is included in PGE's historical energy deliveries data and as such is embedded within PGE's regression based load forecast.

Q PGE has previously requested the ability to update the RVOS price annually, with the understanding that not every element may have an update each year. Does PGE still advocate for the ability to update capacity annually?

A. Yes. Solar penetration on PGE's system is forecast to increase rapidly, primarily driven by QF growth. As shown in Figure 5-11 of the 2016 IRP, the capacity contribution of incremental additions of solar resources declines as more solar is added to the system. The ability to update with the most recent pricing and solar penetration will help ensure customers are paying the most appropriate rate for solar generation.

III. Energy Value

Q. Please provide an overview of PGE's calculation of the avoided cost of energy.

A. PGE calculated the avoided cost of energy based on forecasted wholesale market prices. These prices are based on the same inputs used for the monthly wholesale market prices during the resource sufficiency period in PGE's current Schedule 201. PGE provided additional calculations to transform the monthly On- and Off-Peak prices into average daily (24-hour) profiles for each month of each year (12x24 blocks for each year). Workpapers associated with this calculation have been included in the filing.

Q. Please describe how the forecast was extended beyond 2030, the last year of wholesale market prices provided in Schedule 201.

A. The Schedule 201 prices for 2023-2030 were produced using the AURORA model[7] as used in calculating Schedule 201 prices. The model run that was used to produce the prices for Schedule 201 extends through 2050.

Q. Please provide detail regarding how PGE developed the daily profiles.

A. To create the daily profiles, PGE used the hourly price output for the year 2024 from the same Aurora model run used for Schedule 201. Daily shape factor profiles were calculated for each month based on the hourly prices. The average price for each month/hour was calculated by averaging the price of each daily hour in a given month. For example, the average price for hour ending 10 a.m. in January was calculated based on the tenth hour of all 31 days in January. The month/hour prices were then weighted by the number of days in the month and divided by the annual average price to create shape factors.

[7] The AURORA model is described in the 2016 IRP, Chapter 10.

PGE then applied these shape factors to the weighted average annual price (based on the monthly prices discussed above) for each year to create daily profiles for each month of each year (or 12 x 24 blocks).

Q. Why was the year 2024 used to create the shape factors?

A. The year 2024 was selected to create the shape factors because it aligns with Schedule 201, which used this year's monthly peak and off-peak market prices to shape renewable energy prices in the deficiency period.

Q. Utilities were instructed to show how calculated energy prices are representative of a range of hydro conditions. Please explain how PGE's calculated energy prices meet this requirement.

A. The energy prices prepared by PGE for 2023-2050 are based on modeling that accounts for a range of hydro conditions. The monthly generation values modeled for PGE owned and contracted hydro resources are based on average generation calculated in a hydro study that spans 79 years of streamflow conditions. Non-PGE hydro resources within the Western Eenergy Coordinating Council (WECC) are defined in the AURORA model based on an average from U.S. Energy Information Administration (EIA) that covers 12 years of hydro conditions.

Q. Are there other significant factors that impact wholesale market price forecasts in addition to hydro assumptions?

A. Yes. The wholesale market price forecast is impacted by many factors, including, but not limited to: natural gas price forecasts, load forecasts, coal and oil commodity forecasts, fixed cost forecasts, regulatory forecasts for required retirements and additions, resource parameter assumptions, and carbon price assumptions.

IV. Qualifications

Q. Ms. Jordan, please state your educational background and experience.

A. I received a Bachelor of Arts from Reed College and a Masters of Urban and Regional Planning from Portland State University. Prior to my current role at PGE I served as a Senior Financial Analyst in the Corporate Planning Department, providing budgeting and financial management for the IT division. My work experience includes analyst roles with the City of Portland's City Budget Office and nine years in economic development consulting with a focus on real estate development and land use planning.

Q. Does this conclude your testimony?

A. Yes.

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I. Introduction

Q. Please state your name and position with Portland General Electric ("PGE").

A. My name is Brett Sims. My position at PGE is Director of Strategy Integration and Planning. My qualifications are included as Section IV of this testimony.

Q. What is the purpose of your testimony?

A. My testimony is designed to respond to Public Utilty Commission of Oregon (OPUC or Commission) Order No. 17-357 in Docket No. UM 1716, requesting that utilities file proposed resource value of solar (RVOS) element values, along with narrative descriptions and workpapers, as applicable. My testimony will address the Market Price Response (MPR) and Avoided Hedge Value (Hedge) elements.

Q. Has the OPUC given specific direction regarding how to calculate the MPR or Hedge elements?

A. Yes. In Commission Order No. 17-357, the Commission instructed "[T]wo of the elements will use a proxy value as suggested by Energy and Environmental Economics (E3): hedge value and MPR." The order gives further detail as follows:

1. MPR – OPUC Staff (Staff) is to coordinate or facilitate use of E3's model to create a proxy value for MPR that utilities will use in their initial RVOS filing.
2. Hedge Element – Utilities will assign a proxy value of 5% of energy.

Q. Has PGE developed values for both MPR and Hedge elements?

A. Yes. For the hedge element, PGE used the 5% of energy value in the E3 model as instructed by the Commission. A discussion of PGE's concerns with the methodology behind the calculation of the 5% number are detailed in Section II of this testimony. For MPR, PGE has developed an estimate based on documents provided by Staff to facilitate the calculation of the MPR element. A discussion of how the MPR value was calculated is included in Section III of this testimony.

II. Avoided Hedge Value

Q. E3 proposed an avoided hedge value of 5% of energy. Does PGE have insight into how this value was calculated?

A. Yes. PGE's understanding is that this value was derived from the whitepaper "How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest" by Andrew DeBenedictus, David Miller, Jack Moore, Arne Olson, and C.K. Woo. This whitepaper is included as PGE/201.

Q. Please summarize how this whitepaper was used to estimate the avoided cost of hedging for Oregon Utilities.

A. PGE/201, page 2 provides a summary of the results obtained by the authors and applied to the model that E3 provided as part of UM 1716, Staff/100:

> "Using the theory of cross-hedging, this article estimates the risk premium in a forward price based on a sample of daily data for the seven year period of 2003-2009. It shows that there is a risk premium of about 5 percent in the forward price for delivery at the Mid-Columbia (Mid-C) hub of the Pacific Northwest that is rich in hydro generation."

Q. What is PGE's understanding of the methodology underlying the data gathering process for determining the daily Mid-C price for delivery in PGE/201?

A. It is PGE's understanding that the following data was used to determine the daily Mid-C price:

$$P_t = \alpha + \beta G_t + \varepsilon_t$$

where P = daily Mid-C price for delivery;

T = day during the high-load hours of 06:00 – 22:00, Monday – Saturday;

E_t = Random error; and

B = optimal hedge ratio for procuring the MMBTU of natural gas that minimizes spot price variance.

The following three assumptions are made in the execution of the above equation:

1. Natural gas is the likely fuel for marginal generation;
2. The Mid-C market price tends to track the short-run marginal cost of generation;
3. Natural Gas Future Prices on the New York Mercantile Exchange (NYMEX) are actively traded, which enables cross hedging. The equation does not have weather or hydro conditions as drivers because such conditions cannot be accurately forecasted months ahead when making a Mid-C price forecast.

Q. What is PGE's understanding of the methodology used to develop E3's risk premium?

A. PGE understands the E3's calculation of the risk premium to operate as follows:

1. A potential buyer can create an average net spot electricity forecast price, using the methodology outlined in PGE/201, page 73.
2. A 90% confidence interval can be established on this average spot forecast price, represented as [average forecast price] – 1.65σ, this is referred to as "L."
3. When a forward price (F) is at or below L, the contract is profitable, with a 95% probability, from a contract buyer's perspective when compared to the spot

market alternative. If the forward price F is equal to the average spot price forecast, neither the buyer or the seller are disadvantaged.[1]

Q. Does the analysis accurately recreate the hedging strategies and practices of PGE?

A. No. The model detailed in the whitepaper is based on a fairly limited set of data – the spot price of gas traded through Henry Hub index on a single day to set the prices of the Mid-C curve for the following year. PGE primarily purchases natural gas from the AECO and SUMAS hubs and "layers" hedging transactions throughout the year rather than executing all forward hedging on a single day, as assumed in the E3 model.

Q. What impact would layering versus single-day execution have on the results?

A. "Layering" transactions throughout a period allows a party to use market fluctuations to ensure that the party is executing at the most prudent price, and may result in execution prices on the lower end of the market range during the buying period. Assuming that a buyer would purchase all gas futures needed for the year on a single day is not representative of PGE's practices.

Q. Does PGE have any concerns regarding the time period used during this study?

A. Yes. The study provided by E3 uses relatively outdated data sets which utilizes gas prices from 2003-2009, an era that saw gas prices climb from $2.00 to $18.00 per MMBtu. Comparatively, the last seven years have seen gas trade in a narrow range of $1.50 to $8.00.

Q. Did E3 base their forecast on the current resource mix in the Mid-C?

A. No. E3 looks at the average high-load-hour price in the Mid-C, and establishes a correlation between Mid-C average price and the gas price at Henry Hub. However, this data is also

[1] Dbenedictis et. al., pg 74.

relatively outdated and represents a time period when the resource mix in the Mid-C was different than present day.

Q. Please summarize PGE's recommendations for future calculation and refinement of this element.

A. PGE provides the following recommendations to increase accuracy of the hedge value in the future:

1. The time period used as the sample should be updated to reflect current Mid-C resource mix, as well as a more representative sample of recent gas prices.
2. Layering should be taken into account. PGE uses quarterly targets and ranges in its layering methodology and trades over many more days over the course of a given year.
3. The methodology should be updated to measure price correlation with the AECO and/or SUMAS Hubs, which PGE uses more heavily than Henry Hub.

Q. Does PGE have any other concerns with the hedge element?

A. Yes. This is an entirely new element in the State of Oregon, and this value has not been presented, calculated, or utilized in prior proceedings. The avoided risk premium of hedging activities is difficult to quantify and may be highly variable over time. If this element is to be used throughout the RVOS, PGE requests that a more granular study be considered to accurately quantify the inputs and risks this element poses. In the absence of a more granular study, PGE requests acknowledgement that this value may not be representative of current market conditions, current utility practices, and may utilize outdated data.

Additionally, PGE asks that the calculation of the hedge value for purposes of the RVOS – especially during this first calculation of an RVOS price driven by an external whitepaper – not be precedential in nature, and not be used in other dockets.

III. Market Price Response

Q. Please describe PGE's understanding of what the MPR element is intended to measure.

A. PGE understands the MPR element to represent "The change in utility costs due to lower wholesale energy market prices caused by increased solar [Photovoltaic (PV)] production."

Q. Has Staff provided data or methodology to facilitate the calculation of the MPR element?

A. Yes. Staff has provided multiple whitepapers to assist with the calculation of MPR.

Q. Has PGE calculated an MPR value?

A. Yes. PGE has estimated an MPR value of $1.81 per MWh of incremental solar generation in the Western Electricitry Coordinating Council (WECC) at the 100MW level. At the 1,000MW level, PGE saw an impact of $1.61 per MWh of incremental solar generation.

Q. Please explain the methodology behind PGE's MPR results.

A. PGE ran two scenarios with differing assumptions regarding solar penetration within the WECC region – 100MW and 1000MW. AURORAxmp (AURORA), the program that PGE used, simulated wholesale power market prices in the WECC from 2020-2045. Within the simulation, solar resources were added to the WECC's regional resources, not to PGE's portfolio.

Q. Please provide additional detail regarding the AURORA simulation of MPR.

A. AURORA is a wholesale power market forecasting tool that simulates hourly market clearing prices by calculating the regional electricity demand. This is done by simulating operation of regional resources to meet regional demand and reliability standards, while minimizing total system costs. AURORA calculates PGE's portfolio costs in this simulation based on market purchases, sales, and generation.

We used Wood Mackenzie's "2017 H1 North America Natural Gas Long-Term Outlook" for the model's gas price assumptions, and we removed the impact of potential carbon (CO_2) pricing, since this is captured in the "environmental compliance" element. These assumptions are consistent with PGE's 2016 Integrated Resource Plan (2016 IRP) no carbon case. All financial parameters are consistent with the 2016 IRP.

Q. Does your MPR study differ from E3's methodology?

A. Yes. E3's methodology estimates an average impact on annual solar-hour Mid-C prices under a specified level of solar penetration. The wholesale price impact of this incremental solar is estimated to be constant across the years included in the study. The price impact during solar hours are multiplied by the net purchases or sales that a utility transacts in the Mid-C market.

PGE's methodology calculates PGE's forecasted portfolio cost on an hourly basis and measures how those costs are affected by a specified level of solar penetration. By measuring this impact on portfolio costs, we attempt to capture the MPR impact on the volume and value of market purchases and sales. On an hourly basis, the impact of incremental solar on the wholesale market price could be either a positive or negative value.

Q. Did PGE run a comparison scenario?

A. Yes. PGE also ran a scenario that used a combined cycle combustion turbine (CCCT) as the avoided resource, per instruction in Commission Order No. 17-357. All other parameters in the simulation were held constant and the market impact of the CCCT gas resource (100MW H-Class CCCT) was approximately $0.86 per MWh of new gas generation at the 100MW level. When we ran the simulation with a 1000MW H-Class CCCT, the observed impact was $0.66 per MWh of incremental gas generation.

Q. Does PGE have concerns with the calculation of this element?

A. Yes. The quantification of a MPR element is a new concept in Oregon. There are multiple reasons why PGE urges caution when calculating or applying the MPR value to resources.

PGE is concerned that the MPR element may partially double count a resource's energy value. If a solar resource delivers value by reducing the wholesale market price (and reducing the cost of market purchases), then the solar resource should also receive a diminished energy value. The proposed MPR element does not account for this potential double counting. PGE suggests that this potential interaction be revisted in future filings.

Attributing a consistent levelized value to a market impact that may be highly variable over time also concerns PGE. For example, as seen in PGE/207, there are actually eight years in which PGE's portfolio costs are expected to increase at the 100MW level. At the 1000MW level, there are no years in which the portfolio costs are expected to increase. Thus, an over-estimation of what level of incremental solar penetration is achievable may result in overpayments to solar generators.

Additionally, PGE points out that market price suppression is not a characteristic unique to the addition of solar generation into the wholesale marketplace. Any resource that generates into the wholesale market has the ability to lower wholesale market prices as the supply of power is increased. Therefore, solar generation that displaces a planned or existing renewable resource would theoretically not provide an MPR value.

Q. Please summarize PGE's recommendations for future calculation and refinement of this element.

A. When quantifying the additional solar generation impact on wholesale power market prices, it is important that the methodology accounts for the resource's impact on the volume and price market purchases and sales on a portfolio basis.

At this time, the MPR value of solar resources is small, and likely exceeds the precision that our modeling tools can provide. The element should require careful application as to avoid double counting of value or providing an inflated value based on over-estimation of incremental generation. PGE advocates for a small MPR value consistent with PGE's 100MW results. The value and methodology should be revisited regularly throughout the RVOS. Until concerns with respect to this value are addressed, the MPR value should not be considered precedential in nature, and should not be used in other dockets.

IV. Qualifications

Q. Mr. Sims, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Business and Economics from Linfield College in 1990 and a Master of Business Administration degree from George Fox University in 2001. Previously, I was the Director of Origination, Structuring, and Resource Strategy at PGE. I have also held other managerial positions at a variety of banking and energy companies prior to working at PGE.

Q. Does this conclude your testimony?

A. Yes.

Andrew DeBenedictis *is a Consultant at Energy and Environmental Economics, Inc. (E3), an economics and engineering consulting firm in San Francisco. He has prepared testimony for use in regulatory proceedings and performed analyses of bill impacts and costs of service that involve large billing and load data files. He holds a B.A. in Physics from Bowdoin College.*

David Miller *is a Consultant at E3. He has performed cost effectiveness analyses of various energy technologies for use in California public regulatory proceedings and has created dispatch simulation models. He holds a B.A. in Economics from Stanford University.*

Jack Moore *is a Senior Consultant at E3, specializing in resource planning and distributed resources. He has conducted research and analysis for the California ISO, the Environmental Protection Agency, Electric Power Research Institute, Pacific Northwest Generating Cooperative, and the State Of Idaho. He holds an M.Sc. in Management Science and Engineering from Stanford University.*

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How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest

The numerous benefits of electricity forward trading come at a cost to consumers when a forward price contains a risk premium. An analysis based on the theory of cross hedging suggests that there is a risk premium of about 5 percent in the forward price for delivery at the Mid-Columbia hub of the Pacific Northwest. The existence of a relatively large risk premium suggests that forward contract buyers are more risk-averse than sellers.

Andrew DeBenedictis, David Miller, Jack Moore, Arne Olson and C.K. Woo

I. Introduction

Wholesale spot market prices for electricity generation are inherently volatile, chiefly due to daily fuel cost variations, fluctuating weather-sensitive demands that must be met in real time by capacity already in place, and planned and unexpected facility outages.[1] Unmitigated spot price volatility can be very costly to electricity consumers, as dramatically demonstrated by the California energy crisis a decade ago.[2] To mitigate the spot price volatility, an electricity consumer may buy a forward contract which sets a fixed price for future delivery.[3]

Electricity forward trading offers several benefits to electricity consumers, including

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price discovery, hedge against spot price risk, and market power mitigation.[4] However, these benefits come at a cost to consumers when the forward price contains a risk premium, measured by the percentage above an unbiased spot price forecast. This raises a substantive question: how big is this premium?

Using the theory of cross hedging,[5] this article estimates the risk premium in a forward price based on a sample of daily data for the seven-year period of 2003–09. It shows that there is a risk premium of about 5 percent in the forward price for delivery at the Mid-Columbia (Mid-C) hub of the Pacific Northwest that is rich in hydro generation.[6] Corroborating the empirical evidence for a wholesale market dominated by thermal generation (e.g., PJM), the existence of a relatively large risk premium suggests that forward contract buyers are more risk averse than sellers.[7]

II. Model

A. Cross hedging

Consider P_t, the daily Mid-C price for delivery on day t during the high-load-hours of 06:00–22:00, Monday–Saturday. We assume the data generating process (DGP) for P_t is the following regression:

$$P_t = \alpha + \beta G_t + \varepsilon_t; \qquad (1)$$

where G_t = daily spot natural gas price for Henry Hub delivery; ε_t = random error; and (α, β) = coefficients to be estimated.

Our DGP assumption is based on: (1) natural gas is the likely fuel for marginal generation; (2) the Mid-C market price tends to track the short-run marginal cost of generation; and (3) NYMEX natural gas futures are actively traded which enables cross hedging. Eq. (1)

Using the theory of cross hedging, this article estimates the risk premium in a forward price based on a sample of daily data for a seven-year period.

does not have weather or hydro conditions as drivers for the Mid-C price because such conditions cannot be accurately forecasted months ahead when making a Mid-C price forecast, say, in early 2010 for the 12-month delivery in 2011.

Given suitable data, one can apply ordinary least squares (OLS) to estimate Eq. (1), yielding its estimated version:

$$P_t = a + bG_t + e_t$$

The slope estimate b is the optimal hedge ratio for procuring the MMBTU of natural gas that minimizes the spot price variance.[8]

B. Spot price forecast

Suppose an electricity buyer (e.g., a load-serving entity transacting in the wholesale market) buys b MMBTU of natural gas futures at $\$H_n$/MMBTU for future delivery on day n. Further suppose the buyer takes natural gas delivery and resells the same in the natural gas spot market, realizing a cash flow of $b(G_n - H_n)$. Thus, the buyer's net spot electricity price for day n is:

$$P_n = a + bG_n - b(G_n - H_n) + e_n, \\ = a + bH_n + e_n \qquad (2)$$

Based on Eq. (2), an unbiased forecast of P_n is

$$\mu_n = a + bH_n,$$

whose variance is

$$\sigma_n^2 = \mathrm{var}(a) + 2\,\mathrm{cov}(a,b)H_n + \mathrm{var}(b)H_n^2 + \mathrm{var}(e_n). \qquad (3)$$

Since μ_n and σ_n can be generated by a standard statistical package (e.g., PROC REG in SAS), their computation is fast and straightforward.

If the buyer's forecast period has N days (e.g., $N \approx 26$ for January), the period's average forecast price is

$$\mu = \sum_n \frac{\mu_n}{N},$$

whose variance is

$$\sigma^2 = \sum_n \frac{\sigma_n^2}{N^2}.$$

C. Forward pricing and risk premium

Based on the Central Limit Theorem, μ is normally

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distributed.[9] Hence, a 90 percent confidence interval for the average forecast price has an upper bound of $U = \mu + 1.65\sigma$, and a lower bound of $L = \mu - 1.65\sigma$. Consistent with the notion of value-at-risk, L (U) is the price floor (ceiling) under normal circumstances for the actual average price in the forecast period.[10]

When a forward price F is at or below L, the contract is profitable, with a 95 percent probability, from a contract buyer's perspective when compared to the spot market purchase alternative. If F is at or above U, the contract is profitable, with a 95 percent probability, from a contract seller's perspective when compared to the spot market sale alternative. If $F = \mu$, the forward price does not advantage the buyer or seller.

Suppose an observed F is close to U. This suggests that the contract buyer is more risk-averse than the seller, willing to pay a risk premium of

$$\rho = \frac{F - \mu}{\mu}$$

above the average forecast price to eliminate the spot price volatility in the forecast period.

III. Results

A. Monthly spot price regressions

Table 1 presents the descriptive statistics for the daily data used in our regression analysis, showing that Mid-C and Henry Hub prices can be high and volatile. The Phillips–Perron unit-root test statistics indicate that the Mid-C series is stationary at the 1 percent level ($\alpha = 0.01$), and that the Henry Hub price series is stationary at $\alpha = 0.05$.[11] Thus, the regression results reported below are not ''spurious.''[12]

Recognizing that the hedge ratio may vary substantially across months, we estimate Eq. (1) for each month in our seven-year data sample. That is, the January regression is based on the daily data for January in the seven-year period.

Table 2 shows the regression results by month, yielding the following findings:

- The Mid-C monthly mean prices are relatively low at around \$40/MWh in the spring months of March–June and relatively high at above \$55/MWh in the summer months of July and August and the winter month of December.
- The mean squared error, which is var(e_t) in Eq. (3), indicates large unexplained price variances for the months of April–July. This is because spring runoff in these months, instead of natural gas price, is the main driver of Mid-C prices.
- Measured by the adjusted R^2, the regression goodness-of-fit varies substantially across months. It is likely to be low for the low-price months (e.g., 0.05 for June) and high for the high-price months (e.g., 0.86 for September). This is because the high-price months are those likely with natural gas price as marginal generation fuel.
- The optimal hedge ratio given by the slope coefficient estimate b varies substantially across months (e.g., 1.51 for June vs. 9.61 for April), suggesting that

Table 1: Descriptive Statistics for the 2003–2009 Sample of 2,256 Daily Observations

Variable	Mean	Standard Deviation	Minimum	Maximum	Correlation with Mid-C Price	Phillips–Perron Unit Root τ Test Statistics (lags): Singe Mean	Phillips–Perron Unit Root τ Test Statistics (lags): Trend
Mid-C high-load-hour price (\$/MWH)	50.6	18.7	4.0	197.4	1.0	−7.80 (9)	−7.82 (9)
Natural gas price at Henry Hub (\$/MMBTU)	6.64	2.29	1.83	18.4	0.65	−3.35 (9)	−3.37 (9)

Data source: Intercontinental Exchange.

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Table 2: Monthly OLS Regression Results for the Period January 2003–December 2009, Standard Errors in ( ), and "*" = "significant at the 1 percent level".

Variable	January	February	March	April	May	June
Panel A: January–June						
Sample size	187	177	194	187	177	188
Mean Mid-C price	51.5	51.8	46.5	44.7	41.5	36.4
Mean squared error	79.9	37.2	73.7	180.3	185.6	256.8
Adj. R^2	0.54	0.75	0.70	0.65	0.39	0.05
Intercept estimate: *a*	1.295 (3.40)	10.74* (1.83)	-3.15 (2.41)	-16.03* (3.39)	7.96 (3.20)	25.72* (3.34)
Slope estimate: *b*	7.68* (0.510)	6.08* (0.262)	7.59* (0.356)	9.16* (0.489)	4.95* (0.448)	1.51* (0.443)

Variable	July	August	September	October	November	December
Panel B: July–December						
Sample size	186	194	182	195	185	193
Mean Mid-C price	56.8	56.8	51.7	54.2	52.0	63.1
Mean squared error	391.2	56.1	29.3	41.8	52.1	165.6
Adj. R^2	0.23	0.74	0.86	0.83	0.72	0.69
Intercept estimate: *a*	27.96* (4.12)	18.39* (1.74)	22.87* (0.936	21.33* (1.14)	15.92* (1.71)	7.07* (2.81)
Slope estimate: *b*	4.44* (0.594	6.03* (0.259)	4.65* (0.136)	4.90* (0.156)	5.61* (0.254)	7.79* (0.369)

using a single hedge ratio for the entire year may result in sub-optimal cross-hedging effectiveness.

B. Price forecast and risk premium

We use the spot price regressions in Table 2 to make a Mid-C forecast based on the natural gas futures prices from Mar. 26, 2010, the trading day for the delivery months of January through December 2011. **Figure 1** shows the forecast of the monthly average of daily high-load-hour Mid-C prices and the 90 percent confidence intervals for the monthly forecast results. It also shows the quarterly forward prices published in Platts *MegaWatt Daily* on Mar. 26, 2010 for the 12 delivery months in 2011.

Despite the unavailability of monthly forward prices, this figure yields two important observations. First, the quarterly forward prices track but are above the upper bound of the 90 percent confidence interval. Thus, these forward prices imply almost certain *ex ante* profitability for a forward seller who may meet its delivery obligation using spot-market

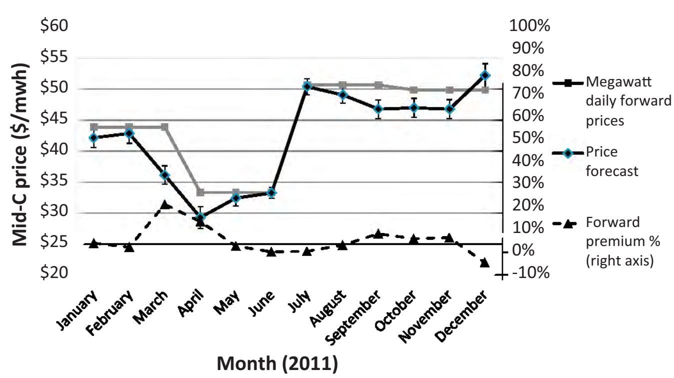

Figure 1: Forecast of Monthly Average of Daily On-Peak Mid-C Prices with 90 percent Confidence Interval and Premium Percentage of MegaWatt Daily's Quarterly Forward PricesBoth the Henry Hub Natural Gas Futures and the Quarterly Forward Prices are Taken from Mar. 26, 2010. The Average Forward-Price Premium is 5.4 Percent

purchases. Second, these forward prices contain an average premium of 5.4 percent above the price forecast.

IV. Conclusion

Dealing with electricity spot-price risk presents electricity buyers with a considerable challenge, one that can be overcome by procuring forward contracts. However, a forward contract is likely to contain a risk premium. Thus, when making a forward purchase, a buyer must necessarily ask: how big is this premium?

To help answer this question, this article provides a readily implementable means for determining if a forward transaction is likely to be profitable from a buyer's (or seller's) perspective when compared to the spot market alternative. It demonstrates that the forward price for Mid-C contains a 5.4 percent risk premium, suggesting that forward-contract buyers are more risk-averse than sellers.■

Endnotes:

1. Asher Tishler, Irena Milstein and Chi-Keung Woo, *Capacity Commitment and Price Volatility in a Competitive Electricity Market*, 30 Energy Econ. 1625–1647 (2008); Ying Li and Peter C. Flynn, *Electricity Deregulation, Spot Price Patterns and Demand-Side Management*, 31 Energy 908–922 (2006); Chi-Keung Woo, Ira Horowitz, Nate Toyama, Arne Olson, Aaron Lai and Raymond Wan, *Fundamental Drivers of Electricity Prices in the Pacific Northwest*, 5 Advances in Quantitative Anal. of Fin. & Acctg. 299–323 (2007).

2. Chi-Keung Woo, Debra Lloyd D and Asher Tishler, *Electricity Market Reform Failures: UK, Norway, Alberta and California*, 31 Energy Policy 1103–1115 (2003); Chi-Keung Woo, Michael King, Asher Tishler and Larry C.H. Chow, *Costs of Electricity Deregulation*, 31 Energy 747–768 (2006).

3. Chi-Keung Woo, Ira Horowitz and Khoa Hoang, *Cross Hedging and Forward-Contract Pricing of Electricity*, 23 Energy Econ. 1–15 (2001).

4. Shijie Deng and Shmuel S. Oren, *Electricity Derivatives and Risk Management*, 31 Energy 940–953 (2006); Frank A. Wolak, *An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market*, 14 Int'l. Econ. J. 1–39 (2000).

5. Ronald W. Anderson and Jean-Pierre Danthine, *Cross Hedging*, 89 J. Political Econ. 1182–1196 (1981).

6. For a description of the Mid-C market, see Woo, Horowitz, *et al.*, *supra note* 1.

7. Hendrik Bessembinder and Michael L. Lemmon, *Equilibrium Pricing and Optimal Hedging in Electricity Forward Markets*, 57 J. Finance 1347–1382 (2002); Francis A. Longstaff and Ashley W. Wang, *Electricity Forward Prices: A High-Frequency Empirical Analysis*, 59 J. Finance 1877–1900 (2004).

8. Sheng-Syan Chen, Cheng-Few Lee and Keshab Shrestha, *Futures Hedge Ratios: A Review*, 43 Q. Rev. Econ. & Finance 433–465 (2003).

9. Robert V. Hogg and Allen T. Craig, Introduction to Mathematical Statistics (Macmillan, 1970) at 182.

10. Chi-Keung Woo, Ira Horowitz and Khoa Hoang, *Cross Hedging and Value at Risk: Wholesale Electricity Forward Contracts*, 8 Advances in Investment Analysis & Portfolio Mgmt. 283–301 (2001).

11. The test is implemented through the AUTOREG procedure of SAS, which automatically determines the optimal number of lags.

12. Russell Davidson and James G. MacKinnon, Estimation and Inference in Econometrics (Oxford Univ. Press, 1993) at 669.

This article provides a readily implementable means for determining if a forward transaction is likely to be profitable.

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Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Darren Murtaugh. I am the Manager of Transmission and Distribution (T&D) Planning and Project Management at PGE. My qualifications appear in Section IV of this testimony.

Q. What is the Purpose of your testimony?

A. My testimony responds to the Public Utility Commission of Oregon (OPUC or Commission) Order No. 17-357 in Docket No. UM 1716 – Investigation into the Resource Value of Solar (RVOS or value of solar). Specifically, I will provide narrative descriptions of the results that PGE has estimated for the Avoided T&D Investment and the Line Loss elements.

Q. Please describe PGE's understanding of what the Avoided T&D Investment and Avoided Line Loss elements are intended to measure.

A. PGE understands the intended use of the two elements to be as follows:

1. Avoided T&D Investment – This element is designed to study how the value of solar and other distributed energy resources differ between geographic locations based on the specific T&D system characteristics in that area, and to estimate avoidable T&D costs.
2. Avoided Line Loss – Avoided Line Loss is intended to estimate the incremental avoided marginal line losses reflecting the hours solar photovoltaic (PV) is generating electricity.

Q. Has the OPUC provided instruction on how to calculate the value of Avoided T&D and Line Loss?

A. Yes. Commission Order No. 17-357 provided direction regarding the calculation of both the T&D and Line Loss elements:

1. Avoided T&D Investment – Utilities should use a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration. The Commission agrees with Energy and Environmental Economics' (E3's) testimony that avoided costs need not be specifically limited to growth-related investments.
2. Line Loss – "We ask the utilities to develop hourly averages of line losses by month for the daytime hours when load on the system is higher, losses are greater, and solar is generating. We expect the utilities' values to recognize and reflect that there are seasonal and daily variations in line loss impacts with higher temperatures and higher loads having higher losses. We do not expect a true hourly value to this element, but ask the utilites to provide the most granular value they reasonably can, incluse of daytime and seasonal variation, with an explanation of the value in their filings."[1]

Q. Has PGE developed calculations for both the T&D and Line Loss elements?

A. Yes. PGE has calculated seasonal and high/light load line loss data. PGE's most recent distribution marginal cost study – which is used as the basis for the avoided T&D value – is included as PGE/401. Bonneville Power Administration (BPA) Tariff BP-18 – which served as the basis for avoided transmission capacity – is attached as PGE/402.

[1] Commission Order No. 17-357, pg. 10.

II. Line Loss

Q. Please describe PGE's methodology for the calculation of the line loss element.

A. PGE calculated peak daylight loading periods for both a heavy and a light system loading scenario. The heavy loading scenario simulates loss data on a day when PGE's system is constrained, while light loading simulates loss data on a day when PGE observes lower system loadings.

Losses were captured for each distribution power transformer in substations, as well as each of their corresponding distribution feeders. For the distribution feeders, losses were calculated for all primary circuits. Utilization transformers, secondary, or service wires were not included in this study.

Q. Did PGE include seasonal variation in the line loss study?

A. Yes. Per the instruction of Commission Order No. 17-357, PGE has conducted analysis that accounts for seasonal variation. Please see PGE/401 for differentiation by summer, winter, and spring.

Q. Commission Order No. 17-357 directed utilities to provide "the most granular value they reasonably can, inclusive of daytime and seasonal variation."[2] Does PGE currently calculate line loss at hourly granularity?

A. No.

Q. Has PGE conducted an hourly analysis of line loss?

A. No. PGE does not currently calculate or analyze line loss data at the hourly level, and requests guidance regarding the appropriate level of granularity if hourly results are sought in this docket. The line loss study that PGE conducted contains the following variables:

[2] Order No. 17-357, page 10

1. Seasonal differentiation; and
2. Heavy loading and light loading to analyze difference in losses based on T&D system constraint;

Q. How did PGE establish system configuration and net load for each period?

A. PGE captured general system configuration for each loading period through records from the System Control Center. The distribution system was modeled via distribution planning software (CYMDIST) to reflect the configuration, and the loading level was provided at the distribution feeder level via PI Processbook. Net system load was estimated in collaboration with PGE's internal transmission planning function.

Q. Was existing distributed solar generation modeled in the line loss studies?

A. Yes. CYMDIST was used to scale loads appropriately per distribution power transformer and distribution feeder. Two separate cases were analyzed: a case modeled with distributed solar "on" throughout the service territory and a case with distributed solar "off." This analysis was achieved by incorporating active solar generation on a per feeder basis. Results of this analysis are included with this filing as workpapers.

Q. Please summarize the results of the distribution loss study:

A. During a heavily loaded period with solar simulated, system loading for the distribution was 3,443 MW, with calculated system losses of 68 MW. The simulated solar modeled in the study considered the full output of the solar resource coincident with the time of system peak load. This equates to approximately 1.98% of the total load attributed to distribution losses. For the purposes of this study, "distribution" is defined as 13kV primary.

For a lightly loaded period with solar simulated, system loading for the distribution system was 2,116 MW, with calculated system losses of 35 MW. This equates to approximately 1.65% of the total load attributed to distribution losses.

When comparing the "solar on" and "solar off" cases, the reduction of losses during a peak period were approximately 0.34%, or approximately 0.7MW.

Q. Commission Order No. 17-357, page 10, reads: "We do not expect a true hourly value to this element, but ask the utilities to provide the most granular value they reasonably can inclusive of daytime and seasonal variation…". What analysis or studies would be required if PGE is to calculate a more granular hourly value in the future?

A. PGE would need to undertake a study of the T&D system and assigning net system load estimates by hour throughout the year. Studying each hour's load/loss in a single year would correspond with 8,760 individual studies of the T&D systems to accurately measure loss characteristics at each system load level.

A more expedient option would be to calculate a handful of representative samples based on net system load estimates. This is similar to the studies that PGE has produced for the initial proposal of the line loss element, but with additional seasonal/daytime variation.

If PGE is asked to conduct studies to reach a more granular line loss value – including perhaps hourly values – PGE requests specific guidance regarding what level of detail is required.

III. Avoided T&D Upgrades

Q. Did the Commission provide direction regarding how PGE should propose the initial value for the avoided T&D upgrade element?

A. Yes. Commission Order No. 17-357 directs utilities to propose values for the avoided T&D element as follows:

> "We retain the straw proposal's approach that utilities' initial RVOS compliance filings should use a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service areas… We have long required utilities to estimate avoidable T&D costs by referencing their most recent studies used to set rates (Marginal Cost of Service Study) and the utilities may continue to use those studies for the first version of RVOS."[3]

Q. Did the Commission also provide guidance regarding the anticipated next steps for this element?

A. Yes. Commission Order No. 17-357 directs utilities to propose values for avoided T&D as follows:

> "[We direct] the utilities to provide additional information on this element in their Phase II initial filings. Specifically, the utilities are to explain in their RVOS filings what information and methodologies they currently have for location specific distribution planning and how those could be used or adapted in the near term to advance the granularity of this element

[3] Order No. 17-357, page 8

> for the next iteration of RVOS…We ask the utilities to address what they can do in the near term to help this element evolve to provide a more location-specific value for their systems."[4]

Q. In PGE's understanding, is the ability to defer a T&D upgrade based solely on capacity-driven upgrades?

A. No. E3 noted that avoided or deferred T&D "will mostly be tied to load growth (e.g.., deferral of a large transformer) but it should not be limited to this circumstance." Commission Order No. 17-357, page 9, Commissioners concur with E3's suggestion that T&D upgrades do not need to be limited to growth-related upgrades.

Q. Has PGE proposed an avoided T&D value?

A. Yes. PGE has proposed a value of $21.52 per kW-year for avoided transmission. PGE has proposed a value of $25.35 per kW-year for avoided distribution. The distribution value is shown in PGE/101. The value for transmission represents the 2018 cost of Long-term Firm Point-to-Point transmission service with Scheduling, System Control, and Dispatch service (from Tariff BP-18) from BPA and is consistent with the per kW-year transmission value used in PGE's Schedule 201 avoided cost pricing.

Q. What is the basis used for calculating the deferred T&D values?

A. In compliance with Commission Order No. 17-357's instruction to use a system-average calculation of deferral value of expanding, replacing, or upgrading T&D investments, PGE has used the marginal cost study prepared for Docket No. UE 319 – PGE's 2018 test year rate case. The value for an avoided distribution asset was estimated to be the cost of subtransmission costs plus substation costs, in dollars per kW-year.

[4] Order No. 17-357, page 9

The avoided transmission value is based on the distributed solar generator's ability to allow PGE to defer the cost of firm transmission service, and the price is based on BPA's 2018 tariffed Firm Point-to-Point transmission service with Scheduling, System Control, and Dispatch Service. This combined value is $21.52 per kW-year for 2018. Escalation rates for both transmission and distribution are estimated to be 2%, which is consistent with the 2016 IRP.

Q. What data may allow a more granular value for the T&D element in the future?

A. PGE continues to advocate for a system-average approach to T&D for this first iteration of the RVOS. In the future, PGE recommends the use of either a consultant study – such as the Draft Storage Potential Evaluation (such as the one Navigant provided for PGE's storage docket – Docket No. UM 1751) – or a modification of PGE's Strategic Asset Management (SAM) calculations to account for deferred investment need.

Q. Why was the Navigant Storage Potential report created?

This report was designed to forecast the predicted benefits of both transmission-sited and distribution-sited energy storage systems (ESSs). Navigant estimated the 10-year Net Present Value (in $/kW) of transmission upgrade deferral at $196 and a distribution benefit of $248. Navigant's report has previously been provided to the Commission in Docket No. UM 1751.

Q. Why is the energy storage potential evaluation report applicable to the T&D RVOS element?

A. Navigant describes their application evaluation for T&D upgrade deferral as follows:

1. Transmission – "Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to

accommodate load growth or regulate voltage or avoiding the purchase of additional transmission rights from third-party transmission providers."

2. Distribution – "Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the system to accommodate load growth or regulate voltage."

These described values are largely synonymous with the defined intent of the T&D RVOS value, which is intended to estimate the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration.

Q. If the T&D element were to use the Navigant study as a basis for calculation, the avoided T&D capacity element have value across all hours of the year?

A. No. PGE, like most utilities, analyzes T&D capacity needs based on system peaks. That is, the T&D systems need to have the capacity and reliability to meet PGE's highest loads. If these systems do not have the necessary capacity or reliability to meet peak loads, an upgrade is needed.

However, the system is not peaking during all hours, and the ability for a distributed resource to defer or displace an upgrade is not based on low-loading periods. Thus, to use a study like the evaluation, shaping and contribution to peak would need to be added, and the value given would need to be translated to kW-year.

Q. Do the estimated values identified in Navigant's study directly correlate with solar benefits?

A. No. The value of the distributed resource as calculated by Navigant is based on the ability of the resource to ease congestion on the T&D system during a time of system constratint. Navigant is basing their research on a resource that is dispatchable. That is, during a transmission system peak and/or a distribution system peak, the energy storage resource can be activated to provide an immediate response to high T&D loadings. Since the study is based on storage, the value per kW takes into account that the ESS will likely be available and responsive when it is needed by the utility to ease transmission and/or distribution congestion.

Solar generation does not have the same ability to dispatch at will, and has a generation shape that does not coincide with PGE's system peaks. To the extent that the solar resource is generating during a time of system constraint for PGE, the value could be comparable to the value outlined in the Navigant study.

Q. You mention modifying the SAM calculations to determine deferred investment. Please describe PGE's SAM department.

A. As further described in Docket No. UE 319, PGE/800, PGE's SAM department developed a robust and proactive asset management strategy that supports traditional load growth planning that also proactively addresses issues related to high-risk infrastructure and the need for system reinvestment. The impetus to develop the strategy was a 2012 study by Black & Veatch to asses PGE's asset management practices and their overall performance against the PAS-55 standards. PGE's prior method for evaluating and managing asset risk was to:

- Use traditional capacity-planning methodologies to proactively identify impacts to the system stemming from load growth;
- Relying on experience of the system, rather than data, to determine the probability of an asset failing and prioritize the replacement of aging/high risk assets based on budget constraints; and

- Reactively replace assets when they failed.

T&D's operating environment is rapidly changing and the past practices of maintaining the system are no longer sufficient and do not recognize the risk and operational impacts various customers experience with due to reliability events.[5] The new asset management strategy is a data-driven, systematic risk assessment methodology that allows PGE to better evaluate its asset base. This methodology is a proactive stance on risk management in the T&D asset base as risks can be systematically identified in the Risk Register by SAM.[6]

Q. Could SAM be implemented to calculate the T&D element immediately?

A. No. Modification would be necessary. PGE is open to exploring this possibility in future iterations of RVOS.

[5] For more information on PGE's changing operational environment, please refer to UE 319, PGE/800, pages 3-4.
[6] For more information on SAM, please refer to UE 319, PGE Exhibit 800, pages 8-16.

IV. Qualifications

Q. Mr. Murtaugh, please state your educational background and experience.

A. I received a Bachelor of Science degree from the University of Nevada in Electrical Engineering in December 2002. I have also received advanced training and coursework from a variety of schools and companies. I obtained my Professional Engineer license in the State of Oregon in December 2007.

In 2012, I accepted my current position as a Manager of T&D Planning and Project Management at PGE. Previously I worked as a Lead Planning Engineer with PGE. Prior to working for PGE, I worked in Transmission Operations with Sierra Pacific Power Company in Reno, Nevada.

Q. Does this conclude your testimony?

A. Yes.

PORTLAND GENERAL ELECTRIC
2018 MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,078,715	$280,770,904
Schedule 15	17,540	$554,684
Schedule 32	1,670,046	$57,329,403
Schedule 38	32,198	$1,135,689
Schedule 47	22,769	$773,334
Schedule 49	70,046	$2,378,448
Schedule 83	2,986,909	$102,934,054
Schedule 85	3,065,104	$104,952,514
Schedule 89	659,052	$22,231,578
Schedule 90-P	1,672,622	$56,202,387
Schedule 91/95	54,173	$1,713,113
Schedule 92	3,040	$102,189
TOTALS	18,332,214	$631,078,295

Load Following Allocation

Schedules	Load Follow Allocation	Allocation
Schedule 7	$8,937,442	71.96%
Schedule 15	($16,694)	-0.13%
Schedule 32	$782,113	6.30%
Schedule 38	$22,709	0.18%
Schedule 47	$10,270	0.08%
Schedule 49	$27,510	0.22%
Schedule 83	$1,360,621	10.96%
Schedule 85	$1,245,252	10.03%
Schedule 89	$93,587	0.75%
Schedule 90	$8,851	0.07%
Schedule 91/95	($51,558)	-0.42%
Schedule 92	($104)	0.00%
TOTAL	$12,420,000	100.00%
LF Marginal Costs ($000)	$12,420,000	

Load Following Requirements (MW)	240
Cost of Flexible Capacity ($/kW)	$157.07
Cost of Conventional Capacity	$105.32
Delta Capacity Cost	$51.75
Load Following Marginal Costs	$12,420,000

PORTLAND GENERAL ELECTRIC
2018 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2018	105.32	30.82	40.88	15.00%	105.32	32.33
2019	107.43	31.43	41.70	15.00%	107.43	32.97
2020	109.58	32.06	42.53	20.00%	109.58	34.16
2021	111.77	32.70	43.38	20.00%	111.77	34.84
2022	114.00	33.36	44.25	20.00%	114.00	35.54
2023	116.28	34.02	45.14	20.00%	116.28	36.25
2024	118.61	34.71	46.04	20.00%	118.61	36.97
2025	120.98	35.40	46.96	27.00%	120.98	38.52
2026	123.40	36.11	47.90	27.00%	123.40	39.29
2027	125.87	36.83	48.86	27.00%	125.87	40.08
2028	128.38	37.57	49.83	27.00%	128.38	40.88
2029	130.95	38.32	50.83	27.00%	130.95	41.70
2030	133.57	39.08	51.85	35.00%	133.57	43.55
2031	136.24	39.87	52.88	35.00%	136.24	44.42
2032	138.97	40.66	53.94	35.00%	138.97	45.31
2033	141.75	41.48	55.02	35.00%	141.75	46.22
2034	144.58	42.31	56.12	35.00%	144.58	47.14
2035	147.47	43.15	57.24	45.00%	147.47	49.49
2036	150.42	44.01	58.39	45.00%	150.42	50.48
2037	153.43	44.90	59.56	45.00%	153.43	51.49
Real Levelized	$105.32	$30.82	$40.88		$105.32	$33.50
NPV	$1,388	$406	$539		$1,388	$442
Nominal Levelized	$123.05	$36.00	$47.76		$123.05	$39.14
Real Levelized	$105.32	$30.82	$40.88		$105.32	$33.50

Composite Income Tax Rate			39.94%
Property Tax Rate			1.50%
Inflation Rate			1.84%
Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	9.60%	4.80%
All Equity	50.00%		4.80%
Debt	50.00%	5.77%	2.89%
Cost of Capital			7.69%
After-Tax Nominal Cost of Capital			6.53%
After-Tax Real Cost of Capital			4.61%

PORTLAND GENERAL ELECTRIC
SUMMARY OF TRANSMISSION, DISTRIBUTION AND CUSTOMER MARGINAL COST STUDIES

SCHEDULE	TRANSMISSION COSTS ($/kW)	SUBTRANSMISSION COSTS ($/kW)	SUBSTATION COSTS ($/kW)	FEEDER MAINLINE COSTS ($/kW)	FEEDER TAPLINE COSTS ($/kW)	TRANSFORMER & SERVICE COSTS ($/Customer)	METER COSTS ($/Customer)	CUSTOMER COSTS ($/Customer)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Schedule 7 Residential								
Single-phase	$86.31	$12.94	$12.41	$24.36	$16.02	$75.35	$20.73	$59.16
Three-phase	$86.31	$12.94	$12.41	$24.36	$16.02	$128.27	$62.80	$59.16
Schedule 15 Residential	$86.31	$12.94	$12.41	$25.56	$18.16	$2.67	N/A	$12.53
Schedule 15 Commercial	$86.31	$12.94	$12.41	$25.56	$18.16	$2.67	N/A	$14.18
Schedule 32 General Service								
Single-phase	$86.31	$12.94	$12.41	$30.20	$23.78	$137.97	$18.32	$58.81
Three-phase	$86.31	$12.94	$12.41	$30.20	$10.43	$205.49	$78.49	$58.81
Schedule 38 TOU								
Single-phase	$86.31	$12.94	$12.41	$30.17	$22.13	$179.91	$62.80	$134.96
Three-phase	$86.31	$12.94	$12.41	$30.17	$10.60	$531.34	$140.82	$134.96
Schedule 47 Irrigation								
Single-phase	$86.31	$12.94	$12.41	$30.20	$23.78	$9.79	$62.43	$56.61
Three-phase	$86.31	$12.94	$12.41	$30.20	$10.43	$19.47	$93.35	$56.61
Schedule 49 Irrigation								
Single-phase	$86.31	$12.94	$12.41	$30.17	$22.13	$131.88	$62.80	$105.66
Three-phase	$86.31	$12.94	$12.41	$30.17	$10.60	$131.88	$77.06	$105.66
Schedule 83 Secondary General Service								
Single-phase	$86.31	$12.94	$12.41	$30.17	$22.13	$356.24	$62.43	$204.99
Three-phase	$86.31	$12.94	$12.41	$30.17	$10.60	$881.44	$139.36	$204.99
Schedule 85 Secondary General Service	$86.31	$12.94	$12.41	$22.40	$7.59	$2,057.03	$175.18	$1,212.63
Schedule 85 Primary General Service	$86.31	$12.94	$12.41	$22.40	$7.59	$0.00	$1,971.73	$1,212.63
Schedule 89 Secondary	$86.31	$12.94	$12.41	$86,625 ($/Customer)	N/A	$13,724.84	$190.01	$8,675.03
Schedule 89 Primary	$86.31	$12.94	$12.41	$86,625 ($/Customer)	N/A	$0.00	$1,975.66	$8,675.03
Schedule 89 Subtransmission	$86.31	$12.94	N/A	$83,765 ($/Customer)	N/A	N/A	$19,913.86	$8,675.03
Schedule 90 Primary	$86.31	$12.94	$12.41	$282,102	NA	$0.00	$1,971.73	$27,734.36
Schedules 91 & 95 Streetlighting	$86.31	$12.94	$12.41	$25.56	$18.16	$2.67	N/A	$943.98
Schedules 92 Traffic Signals	$86.31	$12.94	$12.41	$25.56	$9.17	$8.79	N/A	$941.76

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2018 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2018–2019)

October 2017

United States Department of Energy
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, OR 97232

Bonneville Power Administration's 2018 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions, effective October 1, 2017, and contained herein, were approved on an interim basis by the Federal Energy Regulatory Commission on September 25, 2017. *U.S. Dep't of Energy – Bonneville Power Admin.,* 160 FERC ¶ 61,112 *and* 160 FERC ¶ 61,113 (2017).

These Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions reflect all errata corrections as of the date of publication.

BONNEVILLE POWER ADMINISTRATION

2018 TRANSMISSION, ANCILLARY, AND CONTROL AREA SERVICE RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

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TRANSMISSION, ANCILLARY, AND CONTROL AREA SERVICE RATE SCHEDULES

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FPT-18.1
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-16.1 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once a year. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.662/\text{kW/mo}}\right) * \text{ FPT Base Charges}$$

Where:

GSR_q = The ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	$0.0701 per mile
2.	Main Grid Interconnection Terminal	$0.73/kW
3.	Main Grid Terminal	$0.81/kW
4.	Main Grid Miscellaneous Facilities	$4.00/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	$0.6896 per mile
2.	Secondary System Transformation	$7.54/kW
3.	Secondary System Intermediate Terminal	$2.91/kW
4.	Secondary System Interconnection Terminal	$2.06/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

A. The Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

C. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

D. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

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FPT-18.3
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-16.3 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once every three years. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.634/\text{kW/mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q	=	The ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.
FPT Base Charges	=	The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	$0.0700 per mile
2.	Main Grid Interconnection Terminal	$0.73/kW
3.	Main Grid Terminal	$0.81/kW
4.	Main Grid Miscellaneous Facilities	$3.99/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	$0.6884 per mile
2.	Secondary System Transformation	$7.53/kW
3.	Secondary System Intermediate Terminal	$2.91/kW
4.	Secondary System Interconnection Terminal	$2.06/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

A. The Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking transmission service under FPT agreements are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

IR-18
INTEGRATION OF RESOURCES RATE

SECTION I. AVAILABILITY

This schedule supersedes the IR-16 rate schedule and is available for transmission of non-Federal power for full-year firm transmission service and non-firm transmission service in amounts not to exceed the customer's total Transmission Demand using Federal Columbia River Transmission System Network and Delivery facilities. This schedule is applicable only to Integration of Resource (IR) agreements executed prior to October 1, 1996. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The IR rates in sections A and B, below, are calculated each quarter. These rates shall be calculated to three decimal places. The monthly IR rate shall be as provided in section A or section B.

A. RATE

The rate shall be the sum of:

1. $1.793 per kilowatt per month ($/kW/mo); and

2. ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in $/kW/mo.

B. SHORT DISTANCE DISCOUNT (SDD) RATE

For Points of Integration (POI) specified in the IR agreement as being short-distance POIs, for which Network facilities are used for a distance of less than 75 circuit miles, the monthly rate shall be the sum of:

1. ACS-18 Scheduling, System Control, and Dispatch Rate for Long-Term Firm PTP Transmission Service, section II.A.1.b; and

2. ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in $/kW/mo; and

3. (0.6 + (0.4 * transmission distance/75)) * $1.471/kW/mo

Where:

The transmission distance is the circuit miles between a designated POI for a generating resource of the customer and a designated Point of Delivery serving load of the customer. Short-distance POIs are determined by BPA after considering factors in addition to transmission distance.

SECTION III. BILLING FACTORS

The Billing Factor for rates specified in section II shall be the largest of:

A. The annual Transmission Demand, or, if defined in the agreement, the annual Total Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

To the extent that the agreement provides for the IR customer to be billed for transmission service in excess of the Transmission Demand or Total Transmission Demand, as defined in the agreement, at an hourly non-firm rate, such excess transmission service shall not contribute to the Billing Factor for the IR rates in section II, provided that the IR customer requests such treatment and BPA approves such request in accordance with the prescribed provisions in the agreement. The rate for transmission service in excess of the Transmission Demand will be pursuant to the Point-to-Point Rate (PTP-18) for Hourly Non-Firm Service.

When the Scheduled Demand or Ratchet Demand is the Billing Factor, short-distance POIs shall be charged the Rate specified in section II.A. for the amount in excess of Transmission Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support IR transmission service are available under the ACS rate schedule. IR customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in IR service.

B. DELIVERY CHARGE

Customers taking service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. RATCHET DEMAND RELIEF

Under appropriate circumstances, BPA may waive or reduce the Ratchet Demand. An IR customer seeking a reduction or waiver must demonstrate good cause for relief, including a demonstration that:

1. The event that resulted in the Ratchet Demand:

   a. was the result of an equipment failure or outage that could not reasonably have been foreseen by the customer; and

   b. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; or

2. The event that resulted in the Ratchet Demand:

   a. was inadvertent;

   b. could not have been avoided by the exercise of reasonable care;

   c. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; and

   d. was not part of a recurring pattern of conduct by the IR customer.

If the IR customer causes a Ratchet Demand to be established in a series of months during which the IR customer has not received notice from BPA of such Ratchet Demands by billing or otherwise, and the Ratchet Demand(s) established after the first Ratchet Demand were due to the lack of notice, then BPA may establish a Ratchet Demand for the IR customer based on the highest Ratchet Demand in the series. This highest Ratchet Demand will be charged in the month it is established and the following 11 months. All other Ratchet Demands based on such a series (including the Ratchet Demand established in the first month if it is not the highest Ratchet Demand) will be waived.

Ratchet Demand Relief is not available in the month in which the Ratchet Demand was established. For that month, the Customer will be assessed charges based upon the highest hourly Scheduled Demand Billing Factor.

E. SELF-SUPPLY OF REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

A credit for self-supply of Reactive Supply and Voltage Control from Generation Sources Service will be available for IR customers on a basis equivalent to the credit for PTP Transmission Customers.

F. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

G. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

NT-18
NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-16 rate schedule. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities, including Conditional Firm (CF) Service. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

$1.727 per kilowatt per month

SECTION III. BILLING FACTOR

The monthly Billing Factor shall be the customer's Network Load on the hour of the Monthly Transmission System Peak Load.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support NT Service are also available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking NT Service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking NT Service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. SHORT-DISTANCE DISCOUNT (SDD)

A Customer's monthly NT bill shall be adjusted to reflect a Short Distance Discount (SDD) when a Customer has a resource that (1) is designated as a Network Resource (DNR) in the customer's NT Service Agreement for at least 12 months, and (2) uses FCRTS facilities for less than 75 circuit miles for delivery to the Network Load. A DNR that is a system sale (the DNR is not associated with a specific generating resource) does not qualify for the SDD. Any DNR that is eligible for the SDD (DNR SD) must be noted as such in the NT Service Agreement.

The NT monthly bill will be reduced by a credit equal to:

$$\text{Avg. Generation of the DNR SD during HLH} \;*\; \text{NT Rate} \;*\; \frac{75\text{–Tx Distance}}{75} \;*\; 0.4$$

Where:

Average Generation during HLH =	The output serving Network Load during HLH on a firm basis over the billing month, divided by the number of HLH during the month, multiplied by the ratio of the Qualifying Capacity of the DNR SD output serving the Customer's Point(s) of Delivery (POD) to the total DNR SD designated capacity. The output serving Network Load is: 1. in the case of a scheduled DNR SD, the sum of firm schedules to Network Load. 2. in the case of Behind the Meter Resources, the metered output of the resource.
NT Rate =	$1.727 per kilowatt per month

Tx Distance = The contractually specified distance measured in circuit miles between the DNR SD Point of Receipt (POR) and the Customer's nearest POD(s) within 75 circuit miles of the DNR SD.

1. BPA shall use the peak load for the prior calendar year for the POD nearest to the DNR SD to calculate how much of the DNR SD's designated capacity is allocated to that POD. If the peak load for the prior calendar year of the closest POD is less than the DNR SD's designated capacity, then BPA shall use the next nearest POD that is within 75 circuit miles of the DNR SD, continuing until the DNR SD's designated capacity is fully allocated to the qualifying PODs, subject to section 2 below. The Tx Distance shall be the sum of the distance from the DNR SD to each of the PODs, weighted by the DNR SD designated capacity allocated to each POD.
2. The amount of designated capacity from all DNR SD allocated to any POD may not exceed the POD's peak load.
3. For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Tx Distance shall be zero.

Qualifying Capacity = The sum of all DNR SD designated capacity allocated to the Customer's POD(s).

For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Qualifying Capacity shall be the total DNR SD designated capacity.

Behind the Meter Resource = A resource that is used solely to serve the NT Customer's Network Load and is internal to the NT Customer's system.

E. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Customer under an applicable rate schedule.

F. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Network Customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA to construct Network Upgrades shall be subject to the higher of the rates specified in section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

G. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

H. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

I. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

PTP-18
POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes the PTP-16 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, including Conditional Firm (CF) Transmission Service , and for hourly non-firm service over such FCRTS facilities for customers with Integration of Resources agreements. Terms and conditions of PTP service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.471 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. **Days 1 through 5** $0.068 per kilowatt per day

b. **Day 6 and beyond** $0.048 per kilowatt per day

2. Hourly Firm and Non-Firm Service

4.23 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM AND NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Network are available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking PTP Transmission Service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

    a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

    b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

E. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of the Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

F. SHORT-DISTANCE DISCOUNT (SDD)

Reservations for Long-Term Firm PTP Transmission Service that use BPA transmission facilities for a distance of less than 75 circuit miles shall receive a SDD. The SDD shall be designated in the PTP Service Agreement.

For reservations receiving a SDD, BPA will multiply the billing factors in section III.A. by the following factor to calculate the customer's monthly transmission bill:

$$0.6 + (0.4 * \text{transmission distance} / 75).$$

System sales do not qualify for SDD. If a set of contiguous PODs qualifies for an SDD, the transmission distance used in the calculation of the SDD shall be between the POR and the POD farthest from the POR.

If the customer redirects, on a firm or non-firm basis, any portion of Reserved Capacity from a reservation receiving a SDD for any period of time during a month, the SDD shall not be applied to the entire reservation for that month.

G. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

H. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the PTP Transmission Customer under an applicable rate schedule.

I. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

J. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

K. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

L. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

IS-18
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-16 rate schedule. It is available to Transmission Customers taking Point-to-Point Transmission (PTP) Service over the Federal Columbia River Transmission System (FCRTS) Southern Intertie facilities. Terms and conditions of service are specified in the Open Access Transmission Tariff or, for customers that executed Southern Intertie agreements with BPA before October 1, 1996, will be as provided in the customer's agreement with BPA. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.038 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. **Days 1 through 5** $0.048 per kilowatt per day

b. **Day 6 and beyond** $0.034 per kilowatt per day

2. Hourly Firm and Non-Firm Service

9.56 mills per kilowatthour

BPA intends to provide discounted service for Hourly Non-Firm Service in the south-to-north direction. BPA will post such discount on OASIS pursuant to section II.E of the GSRPs. The following principles will apply to any such discount:

a. Providing a discount for service in one direction will not require the same discount to be provided in the other direction.
b. Providing a discount for service on the Southern Intertie will not require a discount to be provided for service on the Network or other segments.

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all services shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

For Southern Intertie transmission agreements executed prior to October 1, 1996, the Billing Factor shall be as specified in the agreement.

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Southern Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge specified in GRSP II.B.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

   a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

   b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee specified in GRSP II.D.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

I. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

IM-18
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-16 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on the Eastern Intertie. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$0.509 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. **Monthly, Weekly, and Daily Short-Term Firm and Non-Firm Service**

   a. **Days 1 through 5** $0.023 per kilowatt per day

   b. **Day 6 and beyond** $0.017 per kilowatt per day

2. **Hourly Firm and Non-Firm Service**

   1.46 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in section II.A. and II.B. for all services shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Montana Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY CHARGE

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

   a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

   b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule for the hour.

2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

I. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

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UFT-18
USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-16 rate schedule unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand/capacity reservations specified in the agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands/capacity reservations (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with section III.

SECTION III. DETERMINATION OF TRANSMISSION RATE

A. From time to time, but not more often than once a year, BPA shall determine the following data for the facilities that have been constructed or otherwise acquired by BPA and that are used to transmit electric power:

1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

   The annual cost per kilowatt of facilities listed in the agreement that are owned by another entity and used by BPA for making deliveries to the transferee shall be determined from the costs specified in the agreement between BPA and such other entity.

2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used, divided by the sum of Transmission Demands/capacity reservations. The annual cost per kilowatt of Transmission

Demand/capacity reservation for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

A = The annual cost of such facility as determined in accordance with A.1. above.
D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

For facilities used solely by one customer, BPA may charge a monthly amount equal to the annual cost of such sole-use facilities, determined in accordance with section III.A.1., divided by 12.

For facilities used by more than one customer, BPA may charge a monthly amount equal to the annual cost of such facilities prorated based on relative use of the facilities, divided by 12.

SECTION IV. DETERMINATION OF BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor shall be the largest of:

A. The Transmission Demand/capacity reservation in kilowatts specified in the agreement;

B. The highest hourly Measured or Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that are required to support UFT transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

AF-18
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-16 rate schedule and is available to customers that execute an agreement that provides for BPA to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

A. Interconnection or integration of resources and loads to the FCRTS;

B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or

C. Other transmission service arrangements, as determined by BPA.

Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

The charge is:

A. The sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement; or

B. An advance payment equal to the sum of the capital and related costs for specified FCRTS facilities, as provided in the agreement. A credit for some or all of the amount advanced will be applied against charges for transmission service, as provided in the agreement. The charges for transmission service shall be at the rate for the applicable transmission service.

SECTION III. PAYMENT

A. ADVANCE PAYMENT

Payment to BPA shall be specified in the agreement as one of the following options:

1. A lump sum advance payment;

2. Advance payments pursuant to a schedule of progress payments; or

3. Other payment arrangement, as determined by BPA.

Such advance payment or payments shall be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. ADJUSTMENT TO ADVANCE PAYMENT

For charges under section II.A., BPA shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA. The customer will either receive a refund from BPA or be billed for additional payment for the difference between the advance payment and the actual capital and related costs.

TGT-18
TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-16 rate schedule and is available to companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), which provides for firm transmission over BPA's section (Garrison to Townsend) of the Montana Intertie. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Columbia River Transmission System. Annual revenues plus credits for government use should equal annual costs of the facilities, but in any given year there may be a surplus or a deficit. Such surplus or deficit for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from non-firm use and credits for all government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower the unit rate will be.

If BPA provides firm transmission service in its section of the Montana (Eastern) Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by BPA for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer.

A. NON-FIRM TRANSMISSION CHARGE

This charge will be filed as a separate rate schedule, the Eastern intertie (IE) rate.

B. INTERTIE CHARGE FOR FIRM TRANSMISSION SERVICE

$$\text{Intertie Charge} = \left[\left((TAC / 12) - NFR \right) * \frac{(CR - EC)}{TCR} \right]$$

SECTION III. DEFINITIONS

A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500 kV Transmission line including terminals, and prior to extension of the 500 kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of: (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs that are appropriately allocable to such facilities, and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by BPA on account of any reduction in Transmission Demand, termination, or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. NFR = Non-firm Revenues, which are equal to (1) the product of the Non-firm Transmission Charge described in II.A. above and the total non-firm energy transmitted over the Townsend-Garrison line segment under such charge during such month; plus (2) revenue received by BPA under any other rate schedules for non-firm transmission service in either direction over the Townsend-Garrison line segment during such month.

C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500 kV transmission facilities as specified in its firm transmission agreement.

D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I and (2) BPA's firm capacity requirement. BPA's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. EC = Exchange Credit for each customer, which is the product of (1) the ratio of investment in the Townsend-Broadview 500 kV transmission line to the investment in the Townsend-Garrison 500 kV transmission line and (2) the capacity BPA obtains in the Townsend-Broadview 500 kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

PW-18
WECC AND PEAK SERVICE RATE

SECTION I. AVAILABILITY

This schedule supersedes the PW-16 rate schedule. The rate below applies to all loads in the BPA Control Area except for loads of customers billed directly by WECC or by Peak Reliability. The WECC and Peak Service rate recovers the costs billed to BPA by WECC and Peak Reliability based on loads in the BPA Control Area. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. WECC RATE

0.05 mills per kilowatthour

B. PEAK RATE

0.05 mills per kilowatthour

SECTION III. BILLING FACTORS

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

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OS-18
OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-16 rate schedule. The Oversupply Rate applies to generators in the BPA Balancing Authority Area that are specified as the source on transmission schedules for the hours that BPA displaces generation pursuant to the Open Access Transmission Tariff (OATT), Attachment P (Oversupply Event Hours), and to customers that purchase power under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate, for the charges to BPA Power Services under section II.C.

The Oversupply Charge shall collect the amounts paid pursuant to OATT Attachment P for the period October 1, 2017, through September 30, 2019. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2018-2019 rate period are billed and fully paid. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

A. OVERSUPPLY RATE

For each month, the Oversupply rate in dollars per megawatthour ($/MWh) shall be:

$$\frac{\textit{Displacement Cost}}{\sum \textit{Scheduled Generation}}$$

Where:

Displacement Cost = the amount BPA paid pursuant to OATT Attachment P to displace output from generating facilities for the calendar month, in dollars.

Scheduled Generation = For each generator in the BPA Balancing Authority Area, the sum of transmission schedules (e-Tags) during Oversupply Event Hours that specify such generator as the source, in megawatthours.

The after-the-fact schedule shall be used for power dynamically transferred out of BPA's Balancing Authority Area.

∑ *Scheduled Generation* = the sum of all Scheduled Generation, in megawatthours.

B. OVERSUPPLY BILLING FACTORS

The billing factor for the monthly Oversupply Rate is the sum of the customer's Scheduled Generation during the month.

C. OVERSUPPLY CHARGES TO BPA POWER SERVICES

Charges to BPA Power Services for its applicable Scheduled Generation under this rate schedule shall be billed to customers purchasing under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate schedules using a Modified TOCA. The charge for each such customer shall be the Oversupply Charge amount charged to BPA Power Services multiplied by each customer's Modified Tier 1 Cost Allocator (TOCA). The Modified TOCA for each customer for each fiscal year is specified in GRSP II.K.

SECTION III. BILLING

A. OVERSUPPLY CHARGE

The Oversupply charge shall be included on bills for the month after Displacement Costs are incurred, subject to the billing cap; *i.e.,* there will be a one-month lag between Scheduled Generation and billing the Oversupply charge. Any Displacement Cost not billed because of the billing cap, or because BPA was unable to determine the full amount of Displacement Cost for the month, shall be included on the following month's bill, subject to the billing cap, and on subsequent bills as necessary until all Displacement Costs have been billed.

B. BILLING CAP

Total billing to all customers for the Oversupply Charges may not exceed $8 million in any one month. If the total Oversupply Charges exceed $8 million in any month, the excess over $8 million shall be billed in the following month, subject to this billing cap. If the billing cap is exceeded in such following month, excess charges shall be billed in each subsequent month, subject to this billing cap, until all charges are billed.

C. BILLING FOR OVERSUPPLY CHARGES TO BPA POWER SERVICES

The charge for BPA Power Services costs (section II.C) shall be separately included on each applicable customer's transmission bill.

IE-18
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-16 rate schedule and is available to companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended) for non-firm transmission service on the portion of Eastern Intertie capacity that exceeds BPA's firm transmission rights. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The rate shall not exceed 1.46 mills per kilowatthour.

SECTION III. BILLING FACTOR

The Billing Factor shall be the scheduled kilowatthours, unless otherwise specified in the Montana Intertie Agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that may be required to support IE transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

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ACS-18
ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-16 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

A. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control, and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response, and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is also required to offer to provide (a) Operating Reserve – Spinning and (b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Services available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

B. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have transmission agreements with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable NERC, WECC, and NWPP standards.

Control Area Services available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

The rates below apply to Transmission Customers taking Scheduling, System Control, and Dispatch Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. RATES

a. NT Service

The rate shall not exceed $0.376 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service

The rate shall not exceed $0.322 per kilowatt per month.

c. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(a) Days 1 through 5 $0.015 per kilowatt per day

(b) Day 6 and beyond $0.011 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.93 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in sections 1.b. and 1.c.(1) and for the Hourly Firm PTP Transmission Service rate specified in 1.c.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control, and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

(1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

(a) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

(b) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

(2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-18).

c. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated pursuant to section II.F.2.a. of the GRSPs.

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources (GSR) Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, the Southern Intertie, and the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. RATES

The rates for GSR Service will be calculated for each quarter, beginning October 2017, according to the formulas below. The rates will be posted on BPA's website and updated as needed. Rates for Long-Term PTP and NT Service and for Short-Term Monthly, Weekly and Daily Service (sections a. and b.(1), below) shall be calculated to three decimal places. Rates for Hourly Service (section b.(2), below) shall be calculated to two decimal places.

a. Long-Term Firm PTP Transmission Service and NT Service

The rate, in dollars per kilowatt per month ($/kW/mo), shall not exceed:

$$\frac{4(N_q + U_{q-1} + Z_{q-1})}{bd - 4S_q}$$

Where:

bd = 501,314 MW-mo = Average of forecasted FY 2018 and FY 2019 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.

N_q = Non-Federal GSR cost ($) to be paid by BPA under a FERC-approved rate during the relevant quarter, as anticipated prior to the quarter.

U_{q-1} = Payments of non-Federal GSR cost ($) made in the preceding quarter(s) that were not included in the effective rate for the preceding quarter(s). Any refunds received by BPA would reduce this cost. U_{q-1} is a true-up for any deviation of non-Federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2017, U_{q-1} is zero.

S_q = Reduction in effective billing demand (MW-mo) for approved self-supply of reactive during the relevant quarter, as anticipated prior to the quarter.

Z_{q-1} = True-up ($) for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2017, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation.

"Relevant quarter" refers to the 3-month period for which the rate is being determined.

b. Short-Term Firm and Non-Firm PTP Transmission Service

(1) Monthly, Weekly, and Daily Firm and Non-firm Service

For each reservation, the rates shall not exceed:

(a) Days 1 through 5 ($/kW/day)

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 5 days}}$$

(b) Day 6 and beyond ($/kW/day)

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 7 days}}$$

(2) Hourly Firm and Non-Firm Service (mills/kilowatthour)

The rate shall not exceed:

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 5 days * 16 hours}}$$

Where:

The "Long-Term Service Rate" specified in the formulas in sections 1.b.(1)(a) and (b) and section 1.b.(2), above, is the rate determined in section 1.a., Long-Term Firm PTP Transmission Service and NT Service, in $/kW/mo.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in sections 1.b. and 1.c.(1) and for Hourly Firm PTP Transmission Service specified in 1.c.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

(1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

(a) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

(b) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

(2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-18).

c. Adjustment for Self-Supply

The Billing Factors in sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

d. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated pursuant to section II.F.2.a. of the GRSPs.

C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.13 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.

(2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

(1) No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1. of this ACS-18 schedule.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (i) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Persistent Deviation was caused by extraordinary circumstances.

E. OPERATING RESERVE – SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA, and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA will determine the Transmission Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve –Spinning Reserve Service from BPA, the rate shall not exceed 11.98 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.78 mills per kilowatthour.

For energy delivered, the generator shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer's Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. BPA will determine the Transmission Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 9.92 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 11.41 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer's Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.13 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.

(2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation for Generation

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program.

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section 1 of this ACS-18 Generation Imbalance Service rate schedule.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

d. No Credit for Negative Deviations During Curtailments

No credit is provided for negative deviations (actual generation greater than schedules) during scheduling periods when a schedule from a generator is curtailed.

e. Exemption from Deviation Band 2

The 10 percent penalty charge under section 1.b., Imbalances Within Deviation Band 2, will not apply to customers participating in a committed 15-minute scheduling program in accordance with the ACS-18 Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and III.E.3.a.(1).

f. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

(1) wind resources
(2) solar resources
(3) new generation resources undergoing testing before commercial operation for up to 90 days

Unless otherwise stated in this section 2, all deviations greater than ± 1.5 percent or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

C. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA and such Spinning Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed 11.98 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.78 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA, and such Supplemental Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 9.92 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 11.41 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

1. APPLICABILITY

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in section 2.c. of this rate schedule.

Variable Energy Resource Balancing Service ("VERBS" or "Balancing Service") is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

2. BALANCING SERVICE FOR WIND RESOURCES

The total charge for Balancing Service is the applicable rate in section 2.a., below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. BALANCING SERVICE RATES

(1) <u>Rate for 30/60 Committed Scheduling</u>

This rate is applicable to customers taking Balancing Service that commit to receive BPA's 30-minute signal for each 60-minute schedule period (30/60 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(a)	Regulating Reserves	\$0.13 per kilowatt per month
(b)	Following Reserves	\$0.42 per kilowatt per month
(c)	Imbalance Reserves	\$0.46 per kilowatt per month

(2) <u>Rate for 30/15 Committed Scheduling</u>

This rate is applicable to customers taking Balancing Service that commit to receive BPA's 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(a)	Regulating Reserves	$0.13 per kilowatt per month
(b)	Following Reserves	$0.42 per kilowatt per month
(c)	Imbalance Reserves	$0.16 per kilowatt per month

(3) <u>Rate for Uncommitted Scheduling</u>

This rate is applicable to customers taking Balancing Service that do not commit to 30/60 or 30/15 scheduling ("uncommitted scheduling").

(a)	Regulating Reserves	$0.13 per kilowatt per month
(b)	Following Reserves	$0.42 per kilowatt per month
(c)	Imbalance Reserves	$0.67 per kilowatt per month

(4) <u>Rate for Customer Supplied Generation Imbalance</u>

This rate is applicable to customers taking Balancing Service under the Customer Supplied Generation Imbalance Pilot Program.

The rate shall be $0.49 per kilowatt per month.

b. BILLING FACTOR

The Billing Factor for rates in section 2.a. is as follows:

(1) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

(2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.

(3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

c. EXCEPTIONS

(1) The rates under section 2.a. above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

(2) Individual rate components under section 2.a.(1)-(3) above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of Balancing Service, including by contractual arrangements for third-party supply.

3. BALANCING SERVICE FOR SOLAR RESOURCES

The total charge for this service is the applicable rate in section 3.a, below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. RATES

(1) Rate for 30/15 Committed Scheduling

This rate is applicable to customers taking Balancing Service that commit to receive BPA's 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

$0.21 per kilowatt per month

(2) Rate for Hourly Scheduling

This rate is applicable to customers taking Balancing Service that do not commit to 30/15 scheduling.

$0.28 per kilowatt per month

b. **BILLING FACTOR**

For each solar plant that has completed installation no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

c. **EXCEPTIONS**

See section 2.c. above.

4. DIRECT ASSIGNMENT CHARGES

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service to the customer if:

a. the customer elected to self-supply in accordance with section 2.c. but is unable to self-supply one or more components to Variable Energy Resource Balancing Service; or

b. the customer has a projected generator interconnection date after FY 2019, but chooses to interconnect during the FY 2018–2019 rate period; or

c. the customer elected to take service under section 2.a.(1), 2.a.(2), or 3.a.(1) above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or

d. the customer elected to take service under section 2.a.(1), 2.a.(2), or 3.a.(1) above, but chooses to take a Balancing Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices; or

e. the customer elected to dynamically transfer its resource out of BPA's Balancing Authority Area, but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.305 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in section 2.

5. INTENTIONAL DEVIATION PENALTY CHARGE

Customers taking Variable Energy Resources Balancing Service under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.J.

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in section 3 below. Dispatchable Energy Resource Balancing Service ("DERBS") is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

The total charge for service is the charge determined by applying the rates in section 1 below, plus Direct Assignment Charges in section 4 below.

1. RATES

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

a.	Incremental Reserves	20.42 mills per kW maximum hourly deviation
b.	Decremental Reserves	3.43 mills per kW maximum hourly deviation

2. BILLING FACTORS

a. The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the five-minute average negative Station Control Error (under-generation), including ramp periods, that exceeds 3 MW for that hour.

b. The hourly billing factor for use of Decremental Reserves is the maximum of the five-minute average positive Station Control Error (over-generation), including ramp periods, that exceeds 3 MW for that hour.

3. EXCEPTIONS

a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's

Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.

d. Five-minute average station control periods where system frequency deviates by more than 68 mHz shall be excluded from determining the maximum positive (Decremental) or negative (Incremental) value of five-minute station control error for the hour.

4. DIRECT ASSIGNMENT CHARGES

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Dispatchable Energy Resource Balancing Service to the customer if:

a. the customer elected to self-supply but is unable to self-supply the Dispatchable Energy Resource Balancing Service; or

b. a customer has a projected generator interconnection date after FY 2019 but chooses to interconnect during the FY 2018-2019 rate period;

c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2018-2019 rate period; or

d. the customer elected to dynamically transfer its resource out of BPA's Balancing Authority Area but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.305 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in GRSP II.C.

B. RATE ADJUSTMENT DUE TO BPA POWER SERVICES ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Customers taking Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, or Operating Reserve – Supplemental Reserve Service under this rate schedule are subject to the Power Risk Mechanisms specified in the BPA Power Rate Schedules, specified in GRSPs II.O, II.P, and II.Q.

C. RATE ADJUSTMENT FOR TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE AND TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking Scheduling, System Control, and Dispatch Service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause and the Transmission Reserves Distribution Clause, specified in GRSPs II.H and II.I.

GENERAL RATE SCHEDULE PROVISIONS

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SECTION I. GENERALLY APPLICABLE PROVISIONS

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A. Approval Of Rates

BPA has requested that the Federal Energy Regulatory Commission grant approval to make these rate schedules and GRSPs effective on October 1, 2017. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These BP-18 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-16 rate schedules (which became effective October 1, 2015) to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts, as amended: the Bonneville Project Act (P.L. 75-329), 16 U.S.C.§ 832; the Pacific Northwest Consumer Power Preference Act (P.L. 88-552), 16 U.S.C.§ 837; the Federal Columbia River Transmission System Act (P.L. 93-454), 16 U.S.C.§ 838; the Northwest Power Act (P.L. 96-501), 16 U.S.C.§ 839; and the Energy Policy Act of 1992 (P.L. 102-486), 16 U.S.C.§ 824(i)–(l).

These BP-18 rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

D. Billing and Payment

1. BILLING PROCEDURE

Within a reasonable time after the first day of each month, BPA shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff and other agreements during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to BPA, or by wire transfer to a bank named by BPA.

2. INTEREST ON UNPAID BALANCES

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by BPA.

3. CUSTOMER DEFAULT

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to BPA on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after BPA notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, BPA may notify the Transmission Customer that it plans to terminate services in sixty (60) days. The Transmission Customer may use the dispute resolution procedures to contest such termination. In the event of a billing dispute between BPA and the Transmission Customer, BPA will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then BPA may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

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A. Delivery Charge

Transmission Customers shall pay a Delivery Charge for service over DSI Delivery and Utility Delivery facilities and equipment.

1. RATES

a. DSI Delivery

Use-of-Facilities (UFT-18) Rate, section III

b. Utility Delivery

$1.283 per kilowatt per month

2. BILLING FACTOR

a. Utility Delivery

The monthly Billing Factor for the Utility Delivery rate in section 1.b. shall be the total load on the hour of the Monthly Transmission Peak Load at the Points of Delivery specified as providing Utility Delivery service.

The monthly Utility Delivery Billing Factor shall be adjusted for customers that pay for Utility Delivery service under the Use-of-Facilities (UFT) rate schedule. The kilowatt credit shall equal the transmission service over the Delivery facilities and equipment used to calculate the UFT charge. This adjustment shall not reduce the Utility Delivery Charge billing factor below zero.

3. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

a. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

b. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

B. Failure To Comply Penalty Charge

If a party fails to comply with BPA's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. Parties that are unable to comply with a dispatch, curtailment, load shedding, or redispatch order due to a *force majeure* on their system will not be subject to the Failure to Comply Penalty Charge provided that they immediately notify BPA of the situation upon occurrence of the *force majeure*.

1. RATES

The Failure to Comply Penalty Charge shall be the greater of 500 mills per kilowatthour or 150 percent of an hourly energy index in the Pacific Northwest.

If no adequate hourly index exists, an alternative index will be used. At least 30 days prior to the use of such index BPA will post on its OASIS Web site the name of the index to be used. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

2. BILLING FACTOR

The Billing Factor for the Failure to Comply Penalty Charge shall be the kilowatthours that were not curtailed, redispatched, shed, changed, or limited within ten (10) minutes after issuance of the order in any of the following situations:

a. Failure to shed load when directed to do so by BPA in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.

b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by BPA in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service Agreement when directed to do so by BPA in accordance with the curtailment or redispatch provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

C. Rate Adjustment Due To FERC Order Under FPA § 212

If, after review by FERC, the NT, PTP, ACS, IS, or IM rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. § 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to the rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective only prospectively from the date of the final FERC order granting final approval of the rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under the rate schedule prior to the effective date of such prospective modification.

D. Reservation Fee

The Reservation Fee is a non-refundable fee that shall be charged to any PTP Transmission Service customer that postpones the Commencement of Service by requesting an extension of the Service Commencement Date specified in the executed Service Agreement.

The Reservation Fee shall be specified in the executed Agreement for transmission service.

1. FEE

The Reservation Fee is nonrefundable and equal to one month's charge for each extension of the Service Commencement Date for the requested Long-Term Firm Point-to-Point Transmission Service.

2. PAYMENT

The Reservation Fee payment for an Extension of the Commencement of Service must be received by BPA Transmission Services within 30 calendar days of the Service Commencement Date of the Transmission Service Request being deferred. If the 30th calendar day is on a Saturday, Sunday or Federal Holiday, the Reservation Fee is due no later than the following Business Day.

E. Transmission and Ancillary Services Rate Discounts

BPA may offer discounted rates for transmission service and for ancillary services provided in conjunction with the provision of transmission service. Three principal requirements apply to discounts for transmission and ancillary services, as follows:

1. any offer of a discount made by BPA must be announced to all Eligible Customers solely by posting on the OASIS;

2. any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and

3. once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for transmission service on a path, from point(s) of receipt to point(s) of delivery, BPA must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that connect to the same point(s) of delivery on the same segment of the transmission system.

A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on BPA's transmission system.

F. Unauthorized Increase Charge (UIC)

Transmission Customers taking Point-to-Point Transmission Service under the PTP, IS, and IM rate schedules shall be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD). BPA will notify a Transmission Customer that is subject to a UIC once BPA has verified the UIC amount.

1. RATES

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

The UIC rate shall be the lesser of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or (ii) 1000 mills per kilowatthour. If FERC eliminates the price cap, the rate will be 500 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its capacity reservation at each POD and POR, to the extent practicable. BPA shall use hourly measurements based on a 10-minute moving average to calculate actual demands at PODs associated with loads that are one-way dynamically scheduled and at PORs associated with resources that are one-way dynamically scheduled. To calculate actual demands at PODs and PORs that are associated with two-way dynamic schedules, BPA shall use instantaneous peak demands for each hour. Actual demands at all other PODs and PORs will be based on 60-minute integrated demands or transmission schedules.

For each hour, BPA will sum these amounts that exceed capacity reservations for all PODs and for all PORs. The Billing Factor for the monthly billing period shall be the greater of the total of the POD hourly amounts or the total of the POR hourly amounts.

3. UIC RELIEF

a. Criteria for Waiving or Reducing the UIC

Under appropriate circumstances, BPA may waive or reduce the UIC to a Transmission Customer on a non-discriminatory basis. A Transmission

Customer seeking a reduction or waiver must demonstrate good cause for relief, including demonstrating that the event that resulted in the UIC:

(1) was inadvertent or was the result of an equipment failure or outage that the Transmission Customer could not have reasonably foreseen;

(2) could not have been avoided by the exercise of reasonable care; and

(3) did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer.

If a waiver or reduction is granted to a Transmission Customer, notice of such waiver or reduction will be posted on the BPA OASIS Web site.

b. Transmission Rate if BPA Waives or Reduces the UIC

If BPA waives or reduces the UIC, the Transmission Customer remains subject to the applicable rates, including Ancillary Services rates, for the Transmission Customer's transmission demand. The following rates shall apply to transmission demand that exceeds the capacity reservations of a Transmission Customer taking service under the PTP, IS, or IM rate schedules if BPA waives or reduces the UIC:

(1) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in the same calendar day, the rate for one day of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.

(2) If BPA waives or reduces the UIC for excess transmission demand on multiple calendar days in the same calendar week, the rate for seven days of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.

(3) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in multiple calendar weeks in the same calendar month, the rate for the number of days in the month of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.

For a Transmission Customer taking Point-to-Point Transmission Service under the PTP, IS, or IM rate schedules, the Billing Factor for rates in this section 3.b. shall be: (a) the Transmission Customer's highest excess transmission demand for which BPA waives the UIC; or (b) if BPA reduces the UIC, the Transmission Customer's highest excess transmission demand that is not subject to the UIC as a result of the reduction.

G. Power CRAC, Power RDC, and NFB Mechanisms

The Power Cost Recovery Adjustment Clause (Power CRAC), Power Reserves Distribution Clause (Power RDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs II.O, II.P, and II.Q.

The Power CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The Power RDC is a deployment of reserves for risk attributed to Power for high-value purposes such as debt retirement and rate reduction. If the Power RDC triggers and the Administrator elects to deploy some reserves under the RDC toward rate reduction, this would be effected through a Dividend Distribution (DD), a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the amount of incremental BPA revenue that can be generated by a Power CRAC during a fiscal year. Except as otherwise provided, the Power CRAC, Power RDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

1. ACS CUSTOMER CHARGES FOR THE POWER CRAC

A specific fraction of the Power CRAC Amount (the total incremental BPA revenue to be collected in a fiscal year if the Power CRAC triggers) will be allocated to each of the three ACS rates subject to the Power CRAC—Regulating and Frequency Response Service (the RFRS CRAC Amount); Operating Reserve – Spinning (the ORSp CRAC Amount); and Operating Reserve – Supplemental (the ORSu CRAC Amount). These rates will be allocated the following fractions of the Power CRAC Amount:

Regulation and Frequency Response Service:	0.38%
Operating Reserve – Spinning Reserve Service:	1.55%
Operating Reserve – Supplemental Reserve Service:	1.55%

The RFRS CRAC Amount, ORSp CRAC Amount, and ORSu CRAC Amount are equal to the Power CRAC multiplied by the respective allocation fractions above. The RFRS, ORSp, and ORSu CRAC Amounts are converted to the RFRS, ORSp, and ORSu CRAC Percentages by dividing the RFRS, ORSp, and ORSu CRAC Amounts by the most recent forecast of revenues for the relevant fiscal year at the RFRS, ORSp, and ORSu rates.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the relevant CRAC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

2. ACS CUSTOMER CREDIT FOR THE POWER DD

A specific fraction of the Power DD Amount (the total decremental BPA revenue to be collected in a fiscal year if the Power DD triggers) will be allocated to each of the three ACS rates subject to the Power CRAC as described above in Section II.G.1., ACS Customer Charges for the Power CRAC.

The RFRS DD Amount, ORSp DD Amount, and ORSu DD Amount are equal to the Power DD multiplied by the respective allocation fractions above. The RFRS, ORSp, and ORSu DD Amounts are converted to the RFRS, ORSp, and ORSu DD Percentages by dividing the RFRS, ORSp, and ORSu DD Amounts by the most recent forecast of revenues for the relevant fiscal year at the RFRS, ORSp, and ORSu rates.

Line items showing a credit will be added to the bills for each service during the 12 months of the applicable year by multiplying the relevant DD Percentage times each of the applicable rates times the billing factors for each rate for each customer.

3. ACS CUSTOMER CHARGES FOR THE EMERGENCY NFB SURCHARGE

A specific fraction of the Emergency NFB Surcharge Amount (the total incremental BPA revenue to be collected in a fiscal year if the Emergency NFB Surcharge triggers) will be allocated to each of the three ACS rates subject to the Emergency NFB Surcharge as described above in Section II.G.1., ACS Customer Charges for the Power CRAC.

The RFRS Surcharge Amount, ORSp Surcharge Amount, and ORSu Surcharge Amount are equal to the Power Emergency NFB Surcharge Amount multiplied by the respective allocation fractions above. The RFRS, ORSp, and ORSu Surcharge Amounts are converted to the RFRS, ORSp, and ORSu Surcharge Percentages by dividing the RFRS, ORSp, and ORSu Surcharge Amounts by the most recent forecast of revenues for the relevant fiscal year at the RFRS, ORSp, and ORSu rates.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the relevant Surcharge Percentage times each of the applicable rates times the billing factors for each rate.

4. POWER CRAC, POWER RDC, AND NFB MECHANISM RATE PROVISIONS

The Power CRAC, Power RDC, and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs II.O, II.P, and II.Q, are incorporated by reference.

H. Transmission Cost Recovery Adjustment Clause (Transmission CRAC)

The Transmission CRAC is an upward adjustment to certain rates that can apply during FY 2018 or FY 2019 or both. It applies to these Transmission rates:

- Network Integration Rate (NT-18)
- Point-to-Point Rate (PTP-18)
- Formula Power Transmission Rate (FPT-18.1)
- Southern Intertie Point-to-Point Rate (IS-18)
- Utility Delivery Rate (GRSPs Section II. A. 1. b.)
- Scheduling, Control, and Dispatch Rate (ACS-18)
- Integration of Resources Rate (IR-18)
- Montana Intertie Rate (IM-18)

1. CALCULATIONS FOR THE TRANSMISSION CRAC

Prior to the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will forecast the end-of-year Accumulated Calibrated Net Revenue for Transmission (Transmission ACNR) for the fiscal year preceding the applicable year. If the forecast Transmission ACNR is less than the Transmission CRAC Threshold for that applicable year by at least $5 million, the Transmission CRAC will trigger and a rate increase will go into effect beginning on October 1 of the applicable year.

a. Calculating the Transmission Calibrated Net Revenue (Transmission CNR) and Transmission Accumulated Calibrated Net Revenue (Transmission ACNR)

The Transmission CNR is the Transmission Net Revenue (NR) plus the Transmission Net Revenue Calibration (Transmission NR Calibration).

Transmission NR for any given fiscal year is defined as transmission function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

The Transmission NR Calibration is the sum of the effects of a class of differences, one difference calculated for each event not forecast in the BP-18 rate case that affects Transmission NR and Transmission cash flow differently by more than $5 million. "Transmission cash flow" here means changes in Financial Reserves Available for Risk Attributed to Transmission. Such events include certain debt management transactions, settlements of contracts, and others. For each event, the impact of the event on Transmission NR will be subtracted from the impact on Transmission cash flow.

The Transmission ACNR is Transmission CNR accumulated since the end of FY 2016. A forecast of Transmission ACNR is used to determine whether the Transmission CRAC Threshold has been reached, and if so, the required Transmission CRAC Amount to be collected. The forecast of Transmission ACNR for use in determining the Transmission CRAC that will apply to FY 2018 rates will be the forecast of Transmission CNR for FY 2017. The forecast of Transmission ACNR for use in determining the Transmission CRAC that will apply to FY 2019 rates will be the sum of the actual Transmission CNR for FY 2017 plus the forecast of Transmission CNR for FY 2018.

b. Calculating the Transmission CRAC Amount

The Transmission CRAC Threshold is an amount of ACNR below which Transmission is considered to have experienced an Underrun. The Underrun amount is equal to the Transmission CRAC Threshold minus forecast Transmission ACNR.

The Transmission CRAC Amount is based on the Underrun, limited by the Maximum Transmission CRAC Recovery Amount (the Transmission CRAC Cap). There are three possibilities:

(1) If the Underrun is less than $5 million, there is no Transmission CRAC.

(2) If the Underrun is greater than or equal to $5 million and less than or equal to $100 million, the Transmission CRAC Amount is equal to the Underrun.

(3) If the Underrun is equal to or greater than $100 million, the Transmission CRAC Amount is equal to $100 million.

The Transmission CRAC Cap and Thresholds are shown in Table B

Table B
Transmission CRAC Annual Thresholds and Caps
(dollars in millions)

ACNR Calculated Near End of Fiscal Year	***CRAC Applied to Fiscal Year***	***Threshold Measured in ACNR***	***Threshold Measured in Reserves for Risk***	***Maximum CRAC Amount (Cap)***
2017	2018	($249)	$99	$100
2018	2019	($212)	$99	$100

c. **Converting the Transmission CRAC Amount to the Transmission CRAC Percentage and Calculating Revised Rates**

The Transmission CRAC percentage is calculated by dividing the Transmission CRAC Amount by the sum of the most recent forecasts of revenues from the applicable rates for the applicable year.

The Transmission CRAC percentage plus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. TRANSMISSION CRAC NOTIFICATION PROCESS

BPA shall follow these notification procedures:

a. **Financial Performance Status Reports**

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function, including Transmission ACNR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of Transmission ACNR.

b. **Notification of Transmission CRAC Trigger**

BPA shall complete a forecast of end-of-year Transmission ACNR in July 2017 for use in calculating the Transmission CRAC applicable to rates in FY 2018, and in September 2018 for use in calculating the Transmission CRAC applicable to rates in FY 2019. If the Transmission CRAC triggers, then BPA shall notify all Customers and rate case parties by late July 2017 of the amount by which BPA intends to adjust rates for FY 2018 due to the Transmission CRAC, and by late September 2018 of the amount by which BPA intends to adjust rates for FY 2019.

Notification will be posted on BPA's Web site and will include the following:

1) the forecast of Transmission ACNR for the current fiscal year;

2) the Transmission NR and the Transmission NR Calibration for FY 2017 in the case of the Transmission CRAC applicable to FY 2019 rates;

3) the Transmission CRAC Amount; and

4) the Transmission CRAC Percentage.

The notification shall also describe the data and assumptions relied upon by BPA for all Transmission ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of Transmission CRAC calculations as described above, BPA shall conduct a workshop(s) to explain the Transmission ACNR calculations, describe the calculation of the Transmission CRAC Amount and allocations to various rates, and demonstrate that the Transmission CRAC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Transmission CRAC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA Web site the final Transmission CRAC calculations. If the Transmission CRAC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA Web site the final Transmission CRAC calculations.

I. Transmission Reserves Distribution Clause (Transmission RDC)

The Transmission RDC is a distribution of financial reserves to purposes such as debt retirement, incremental capital investment, or rate reduction (a Dividend Distribution, or DD) during FY 2018 or FY 2019 or both.

If the RDC quantitative criteria (below) are met, the Administrator will determine how much of any RDC, if any, would be applied to debt reduction, incremental capital investment, a DD, or any other uses.

A DD applies to these Transmission rates:

- Network Integration Rate (NT-18)
- Point-to-Point Rate (PTP-18)
- Formula Power Transmission Rate (FPT-18.1)
- Southern Intertie Point-to-Point Rate (IS-18)
- Utility Delivery Rate (GRSPs Section II. A. 1. b.)
- Scheduling, System Control, and Dispatch Rate (ACS-18)
- Integration of Resources Rate (IR-18)
- Montana Intertie Rate (IM-18)

1. CALCULATIONS FOR THE TRANSMISSION RDC

Prior to the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will forecast the end-of-year Transmission Accumulated Calibrated Net Revenue (Transmission ACNR) and BPA Accumulated Calibrated Net Revenue (BPA ACNR) for the fiscal year preceding the applicable year. If the forecast Transmission ACNR is greater than the Transmission RDC Threshold for that applicable year by at least $5 million and the forecast BPA ACNR is greater than the BPA RDC Threshold for that applicable year by at least $5 million, the Administrator will determine the amount, if any, of a Transmission RDC. If the Administrator determines that part of the RDC will be a DD, the resulting rate decrease will go into effect beginning on October 1 of the applicable year.

a. Calculating the BPA ACNR

The BPA ACNR is the sum of the Transmission ACNR and the Power ACNR. *See* Transmission GRSP II.H.1(a) and Power GRSP II.O.1(a).

b. Calculating the Transmission RDC Amount

The Transmission RDC can only trigger if (1) Transmission ACNR exceeds the Transmission RDC Threshold, measured in Transmission

ACNR, and (2) BPA ACNR exceeds the BPA RDC Threshold, measured in BPA ACNR.

The Transmission RDC Amount is the reduction in financial reserves for risk attributed to Transmission caused by using reserves to retire debt, incrementally fund capital projects, decrease rates by means of a Transmission DD, or further other Transmission objectives during the year of application. The Transmission RDC Amount will be the smallest of the forecast Transmission ACNR less the Transmission RDC Threshold, the forecast BPA ACNR less the BPA RDC Threshold, and the Transmission RDC Cap, or a smaller amount if the Administrator so elects.

Table C
Transmission RDC Annual Thresholds and Caps
(dollars in millions)

ACNR Calculated Near End of Fiscal Year	***RDC Applied to Fiscal Year***	***Threshold Measured in Transmission ACNR***	***Threshold Measured in Transmission Reserves for Risk***	***Maximum RDC Amount (Cap)***
2017	2018	($150)	$199	$200
2018	2019	($113)	$199	$200

Table D
BPA RDC Annual Thresholds
(dollars in millions)

Calculated Near End of Fiscal Year	***RDC Applied to Fiscal Year***	***Threshold Measured in BPA ACNR***	***Threshold Measured in BPA Reserves for Risk***
2017	2018	$506	$606
2018	2019	$758	$606

c. Converting a Transmission DD to the Transmission DD Percentage and Calculating Revised Rates

The Transmission DD percentage is calculated by dividing the Transmission DD Amount by the sum of the most recent forecasts of revenues from the applicable rates for the applicable year.

The Transmission DD percentage minus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. TRANSMISSION RDC NOTIFICATION PROCESS

BPA shall follow these notification procedures:

a. Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function, including Transmission ACNR and BPA ANR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of Transmission ACNR and BPA ACNR.

b. Notification of Transmission RDC Trigger

BPA shall complete a forecast of end-of-year Transmission ACNR and BPA ACNR in July 2017 for use in calculating the Transmission RDC for FY 2018, and in September 2018 for use in calculating the Transmission RDC for FY 2019. If the Transmission RDC triggers, BPA shall notify all Customers and rate case parties by late July 2017 of the amounts BPA intends to use, and by late September 2018 of the amounts BPA intends to use in these ways for FY 2019.

Notification will be posted on BPA's Web site and will include the following:

1) the forecast of Transmission ACNR and BPA ACNR for the current fiscal year;

2) the Transmission NR and the Transmission NR Calibration for FY 2017 in the case of the Transmission RDC applicable to FY 2019;

3) the Transmission RDC Amount;

4) the amounts to be used to retire debt, incrementally fund capital projects or other high-value Transmission purposes, or adjust rates for FY 2018 due to the Transmission DD Amount; and

5) the Transmission DD Percentage.

The notification shall also describe the data and assumptions relied upon by BPA for all Transmission ACNR and BPA ACNR determinations.

BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of Transmission RDC calculations as described above, BPA shall conduct a workshop(s) to explain the Transmission ACNR and BPA ACNR calculations, describe the calculation of the Transmission DD Amount and allocations to various rates, and demonstrate that the Transmission RDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Transmission RDC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA Web site the final Transmission RDC calculations. If the Transmission RDC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA Web site the final Transmission RDC calculations.

J. Intentional Deviation Penalty Charge

1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-18 Variable Energy Resources Balancing Service rate.

Exceptions:

a. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.

b. Customers participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program are not subject to the Intentional Deviation Penalty Charge.

2. RATE

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be $100 per megawatthour (MWh).

An Intentional Deviation event occurs when:

ABS(Intentional Deviation Measurement Value – Resource Schedule) > 1

(See section 3, below, for definition of terms.)

3. BILLING FACTOR

The Billing Factor in MWh shall be:

ABS(Intentional Deviation Measurement Value – Resource Schedule) – 1

Multiplied by

Minutes of schedule divided by 60 minutes

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following:

1) for wind generating customers taking VERBS under rate schedule section 2.a., the applicable schedule value provided by BPA;

2) for solar generating customers taking VERBS under rate schedule section 3.a., the applicable schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer for the scheduling period.

Minutes of schedule = 15 if a 15-minute schedule, 30 if a 30-minute schedule, or 60 if a 60-minute schedule.

4. OTHER PROVISIONS

Exemption from Intentional Deviation Penalty Charge

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

ABS(Station Control Error) ≤ ABS(Intentional Deviation Measurement Value Error) + 1 MW

Where:

ABS(Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value.

K. Modified Tier 1 Cost Allocators (TOCA) for Oversupply Rate

BPA Customer ID	Customer Name	Modified TOCAs FY 2018	FY 2019
10005	Alder Mutual	0.0000784	0.0000782
10015	Asotin County PUD #1	0.0000833	0.0000824
10024	Benton County PUD #1	0.0292395	0.0289494
10025	Benton REA	0.0086666	0.0085806
10027	Big Bend Elec Coop	0.0088895	0.0088013
10029	Blachly Lane Elec Coop	0.0025590	0.0025336
10044	Canby, City of	0.0029503	0.0029210
10046	Central Electric Coop	0.0118903	0.0117724
10047	Central Lincoln PUD	0.0225684	0.0223993
10055	Albion, City of	0.0000577	0.0000573
10057	Ashland, City of	0.0030607	0.0030303
10059	Bandon, City of	0.0011022	0.0010939
10061	Blaine, City of	0.0012706	0.0012580
10062	Bonners Ferry, City of	0.0007728	0.0007651
10064	Burley, City of	0.0020431	0.0020228
10065	Cascade Locks, City of	0.0003453	0.0003419
10066	Centralia, City of	0.0035403	0.0034915
10067	Cheney, City of	0.0022976	0.0022748
10068	Chewelah, City of	0.0003890	0.0003861
10070	Declo, City of	0.0000521	0.0000516
10071	Drain, City of	0.0002756	0.0002737
10072	Ellensburg, City of	0.0034838	0.0034493
10074	Forest Grove, City of	0.0038761	0.0038377
10076	Heyburn, City of	0.0006998	0.0006928
10078	McCleary, City of	0.0005400	0.0005347
10079	McMinnville, City of	0.0128095	0.0126824
10080	Milton, Town of	0.0010804	0.0010697
10081	Milton-Freewater, City of	0.0014313	0.0014171
10082	Minidoka, City of	0.0000149	0.0000147
10083	Monmouth, City of	0.0012149	0.0012028
10086	Plummer, City of	0.0005732	0.0005675
10087	Port Angeles, City of	0.0045501	0.0045163
10089	Richland, City of	0.0150871	0.0149374
10091	Rupert, City of	0.0013687	0.0013551
10094	Soda Springs, City of	0.0004411	0.0004367
10095	Sumas, Town of	0.0005292	0.0005239
10097	Troy, City of	0.0002960	0.0002931
10101	Clallam County PUD #1	0.0110445	0.0109349
10103	Clark County PUD #1	0.0440937	0.0437933

BPA Customer ID	Customer Name	Modified TOCAs FY 2018	FY 2019
10105	Clatskanie PUD	0.0124785	0.0121722
10106	Clearwater Power	0.0034689	0.0034344
10109	Columbia Basin Elec Coop	0.0017605	0.0017430
10111	Columbia Power Coop	0.0004356	0.0004293
10112	Columbia River PUD	0.0082726	0.0082065
10113	Columbia REA	0.0054756	0.0054213
10116	Consolidated Irrigation District #19	0.0000331	0.0000328
10118	Consumers Power	0.0066350	0.0065691
10121	Coos Curry Elec Coop	0.0057361	0.0056791
10123	Cowlitz County PUD #1	0.0797813	0.0789897
10136	Douglas Electric Cooperative	0.0026743	0.0026543
10142	East End Mutual Electric	0.0003903	0.0003865
10144	Eatonville, City of	0.0004817	0.0004778
10156	Elmhurst Mutual P & L	0.0046687	0.0046368
10157	Emerald PUD	0.0072573	0.0071853
10158	Energy Northwest	0.0003893	0.0003855
10170	Eugene Water & Electric Board	0.0350025	0.0347263
10172	U.S. Airforce Base, Fairchild	0.0008154	0.0008114
10173	Fall River Elec Coop	0.0048127	0.0047649
10174	Farmers Elec Coop	0.0000737	0.0000730
10177	Ferry County PUD #1	0.0014586	0.0013905
10179	Flathead Elec Coop	0.0242340	0.0239935
10183	Franklin County PUD #1	0.0170474	0.0168783
10186	Glacier Elec Coop	0.0027057	0.0026947
10190	Grant County PUD #2	0.0007541	0.0007466
10191	Grays Harbor PUD #1	0.0188860	0.0186941
10197	Harney Elec Coop	0.0033051	0.0032723
10202	Hood River Elec Coop	0.0019028	0.0018839
10203	Idaho County L & P	0.0009027	0.0008937
10204	Idaho Falls Power	0.0096998	0.0096243
10209	Inland P & L	0.0152373	0.0150861
10230	Kittitas County PUD #1	0.0014095	0.0013955
10231	Klickitat County PUD #1	0.0053254	0.0052726
10234	Kootenai Electric Coop	0.0074086	0.0073351
10235	Lakeview L & P (WA)	0.0045911	0.0045682
10236	Lane County Elec Coop	0.0040477	0.0040075
10237	Lewis County PUD #1	0.0160252	0.0159072
10239	Lincoln Elec Coop (MT)	0.0020092	0.0019893
10242	Lost River Elec Coop	0.0013636	0.0013609
10244	Lower Valley Energy	0.0124986	0.0123745
10246	Mason County PUD #1	0.0013055	0.0012926

BPA Customer ID	Customer Name	Modified TOCAs FY 2018	FY 2019
10247	Mason County PUD #3	0.0116111	0.0114959
10256	Midstate Elec Coop	0.0066009	0.0065378
10258	Mission Valley	0.0055133	0.0054586
10259	Missoula Elec Coop	0.0039201	0.0038812
10260	Modern Elec Coop	0.0038184	0.0037805
10273	Nespelem Valley Elec Coop	0.0008544	0.0008459
10278	Northern Lights	0.0049072	0.0048815
10279	Northern Wasco County PUD	0.0094082	0.0093149
10284	Ohop Mutual Light Company	0.0014437	0.0014321
10285	Okanogan County Elec Coop	0.0009484	0.0009390
10286	Okanogan County PUD #1	0.0066694	0.0066032
10288	Orcas P & L	0.0035930	0.0035574
10291	Oregon Trail Coop	0.0114283	0.0113884
10294	Pacific County PUD #2	0.0050625	0.0050290
10304	Parkland L & W	0.0020076	0.0019932
10306	Pend Oreille County PUD #1	0.0000000	0.0000000
10307	Peninsula Light Company	0.0099302	0.0098437
10326	U.S. Naval Base, Bremerton	0.0042306	0.0041886
10331	Raft River Elec Coop	0.0053172	0.0052645
10333	Ravalli County Elec Coop	0.0026896	0.0026629
10338	Riverside Elec Coop	0.0003447	0.0003413
10342	Salem Elec Coop	0.0055201	0.0054792
10343	Salmon River Elec Coop	0.0016779	0.0016613
10349	Seattle City Light	0.0754206	0.0753012
10352	Skamania County PUD #1	0.0022512	0.0022332
10354	Snohomish County PUD #1	0.1142959	0.1145352
10360	Southside Elec Lines	0.0009829	0.0009731
10363	Springfield Utility Board	0.0139352	0.0138315
10369	Surprise Valley Elec Coop	0.0023871	0.0023634
10370	Tacoma Public Utilities	0.0554876	0.0565413
10371	Tanner Elec Coop	0.0016026	0.0015867
10376	Tillamook PUD #1	0.0080086	0.0079489
10378	Coulee Dam, City of	0.0002780	0.0002773
10379	Steilacoom, Town of	0.0006940	0.0006907
10388	Umatilla Elec Coop	0.0164477	0.0162845
10391	United Electric Coop	0.0043547	0.0043115
10406	U.S. DOE Albany Research Center	0.0000665	0.0000659
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002131	0.0002109
10409	U.S. Naval Submarine Base, Bangor	0.0028731	0.0028485
10426	U.S. DOE Richland Operations Office	0.0026740	0.0045013
10434	Vera Irrigation District	0.0039450	0.0039059

BPA Customer ID	Customer Name	Modified TOCAs FY 2018	FY 2019
10436	Vigilante Elec Coop	0.0027822	0.0027546
10440	Wahkiakum County PUD #1	0.0007249	0.0007177
10442	Wasco Elec Coop	0.0019267	0.0019140
10446	Wells Rural Elec Coop	0.0139125	0.0137744
10448	West Oregon Elec Coop	0.0012035	0.0011916
10451	Whatcom County PUD #1	0.0038659	0.0038275
10482	Umpqua Indian Utility Cooperative	0.0004003	0.0003963
10502	Yakama Power	0.0024515	0.0025383
13927	Kalispel Tribe Utility	0.0005917	0.0005858
10597	Hermiston, City of	0.0018365	0.0018182
10706	Port of Seattle - SETAC In'tl. Airport	0.0025100	0.0024851
11680	Weiser, City of	0.0009193	0.0009102
12026	Jefferson County PUD #1	0.0064695	0.0064240
10007	Alcoa	0.0071017	0.0109630
10312	Port Townsend Paper	0.0018614	0.0018430
10298	PNGC Aggregate	0.0762502	0.0755231

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SECTION III. DEFINITIONS

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1. **Ancillary Services**

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of BPA's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

a. Scheduling, System Control, and Dispatch
b. Reactive Supply and Voltage Control from Generation Sources
c. Regulation and Frequency Response
d. Energy Imbalance
e. Operating Reserve – Spinning
f. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

2. **Balancing Authority Area**

See definition in Control Area.

3. **Billing Factor**

The Billing Factor is the quantity to which the rate specified in the rate schedule is applied. When the rate schedule includes rates for several products, there may be a Billing Factor for each product.

4. **Control Area**

A Control Area (also known as Balancing Authority Area) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);

b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

5. Control Area Services

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) reliability criteria. Control Area Services include, without limitation:

a. Regulation and Frequency Response Service
b. Generation Imbalance Service
c. Operating Reserve – Spinning Reserve Service
d. Operating Reserve – Supplemental Reserve Service
e. Variable Energy Resource Balancing Service
f. Dispatchable Energy Resource Balancing Service

6. Daily Service

Daily Service is service that starts at 00:00 of any date and stops at 00:00 at least one (1) day later, but less than or equal to six (6) days later.

7. Direct Assignment Facilities

Direct Assignment Facilities are facilities or portions of facilities that are constructed by BPA for the sole use and benefit of a particular Transmission Customer requesting service under the Open Access Transmission Tariff, the costs of which may be directly assigned to the Transmission Customer in accordance with applicable Federal Energy Regulatory Commission policy. Direct Assignment Facilities shall be specified in the service agreement that governs service to the Transmission Customer.

8. Direct Service Industry (DSI) Delivery

The DSI Delivery segment consists of equipment necessary to deliver power to DSI customers at low voltages (i.e., 6.9 or 13.8 kV).

9. Dispatchable Energy Resource

For purposes of the ACS rate schedule, a Dispatchable Energy Resource is any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control system.

10. Dispatchable Energy Resource Balancing Service

Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service that provides imbalance reserves (which compensate for differences between a thermal generator's schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

11. Dynamic Schedule

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. Dynamic Transfer

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

13. Eastern Intertie

The Eastern Intertie is the segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

14. Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area. BPA must offer this service when the transmission service is used to serve load within BPA's Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements specified in the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

15. Federal Columbia River Transmission System

The Federal Columbia River Transmission System (FCRTS) is the transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

16. Federal System

The Federal System is the generating facilities of the Federal Columbia River Power System, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability ("BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer that may be scheduled by BPA);

b. that BPA may use under contract or license; or

c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

17. Generation Imbalance

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

18. Generation Imbalance Service

Generation Imbalance Service is provided when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

19. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the period beginning with the hour ending 7 a.m. through hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable), except for holidays recognized by NERC.

20. Hourly Non-Firm Service

Hourly Non-firm Service is non-firm transmission service under Part II of the Open Access Transmission Tariff in hourly increments.

21. Integrated Demand

Integrated Demand is the quantity derived by mathematically "integrating" kilowatthour deliveries over a 60-minute period. For one-way dynamic schedules, demand is integrated on a rolling ten-minute basis.

22. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the period beginning with the hour ending 11 p.m. through hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

BPA considers as LLH six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day and Thanksgiving occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that a holiday falls on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If a holiday falls on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

23. Long-Term Firm Point-To-Point (PTP) Transmission Service

Long-Term Firm Point-to-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of one year or more.

24. Main Grid

As used in the FPT rate schedule, the Main Grid is that portion of the Network facilities with an operating voltage of 230 kV or more.

25. Main Grid Distance

As used in the FPT rate schedules, Main Grid Distance is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

26. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid Interconnection Terminal refers to Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

27. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, Main Grid Miscellaneous Facilities refers to switching, transformation, and other facilities of the Main Grid not included in other components.

28. Main Grid Terminal

As used in the FPT rate schedules, Main Grid Terminal refers to the Main Grid terminal facilities located at the sending and/or receiving end of a line, exclusive of the Interconnection terminals.

29. Measured Demand

The Measured Demand is that portion of the customer's Metered or Scheduled Demand for transmission service from BPA under the applicable transmission rate schedule. If transmission service to a point of delivery or from a point of receipt is provided under more than one rate schedule, the portion of the measured quantities assigned to any rate schedule shall be as specified by contract. The portion of the total Measured Demand so assigned shall be the Measured Demand for transmission service for each transmission rate schedule.

30. Metered Demand

Except for dynamic schedules, the Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered (received) for a transmission customer:

a. at each point of delivery (receipt) for which the Metered Demand is the basis for the determination of the Measured Demand;

b. during each time period specified in the applicable rate schedule; and

c. during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accord with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the customer.

For one-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest ten-minute moving average of the load (generation) at the point of delivery (receipt). The ten-minute moving average shall be assigned to the hour in which the ten-minute period ends. For two-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest instantaneous value of the Dynamic Schedule during the hour.

31. Montana Intertie

The Montana Intertie is the double-circuit 500 kV transmission line and associated substation facilities from Broadview Substation to Garrison Substation.

32. Monthly Services

Monthly Service is service that starts at 00:00 on any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later.

33. Monthly Transmission Peak Load

Monthly Transmission Peak Load is the peak loading on the Federal Transmission System during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's Control Area and metered flow into BPA's Control Area.

34. Network

The Network consists of facilities that transmit power from Federal and non-Federal generation sources, from interconnections with other utilities, or from the interties, to the load centers of BPA's transmission customers in the Pacific Northwest, to interconnections with other utilities, or to other segments (*e.g.*, an intertie or delivery segment).

35. Network Integration Transmission (NT) Service

Network Integration Transmission (NT) Service is the transmission service provided under Part III of the Open Access Transmission Tariff.

36. Network Load

Network Load is the load that a Network Customer designates for Network Integration Transmission Service under Part III of the Open Access Transmission Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery.

Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-to-Point Transmission Service that may be necessary for such non-designated load.

37. Network Upgrades

Network Upgrades are modifications or additions to transmission-related facilities that support the BPA Transmission System for the general benefit of all users of such Transmission System.

38. Non-Firm Point-to-Point (PTP) Transmission Service

Non-Firm Point-To-Point Transmission Service is Point-To-Point Transmission Service under the Open Access Transmission Tariff that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption as set forth in section 14.7

under Part II of the Tariff. Non-Firm PTP Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

39. Operating Reserve – Spinning Reserve Service

Operating Reserve – Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

40. Operating Reserve – Supplemental Reserve Service

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency. It is not available immediately to serve load, but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

41. Operating Reserve Requirement

Operating Reserve Requirement is a party's total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

42. Persistent Deviation

A Persistent Deviation event is one or more of the following:

a. **For Generation Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

(1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;

(2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. **For Energy Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

(1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;

(2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

c. A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day.

43. Point of Delivery (POD)

A Point of Delivery is a point on the BPA Transmission System, or transfer points on other utility systems pursuant to section 36 of the Open Access Transmission Tariff, where capacity and energy transmitted by BPA will be made available to the Receiving Party under Parts II and III of the Tariff or to the Transmission Customer under other BPA transmission service agreements. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

44. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically, a point of integration is located at a resource site, but it could be located at some other interconnection point.

45. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected. This term is used in certain pre-Open Access Transmission Tariff service agreements and has the same meaning as "Point of Integration" and "Point of Receipt."

46. Point of Receipt (POR)

A Point of Receipt is a point of interconnection on the BPA Transmission System where capacity and energy will be made available to BPA by the Delivering Party under Parts II and III of the Open Access Transmission Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

47. Ratchet Demand

The Ratchet Demand in kilowatts or kilovars is the maximum demand established during a specified period of time during or prior to the current billing period. The Ratchet Demand shall be the maximum demand established during the previous 11 billing months. If a Transmission Demand has been decreased pursuant to the terms of the transmission agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

48. Reactive Power

Reactive Power is the out-of-phase component of the total volt-amperes in an electric circuit. Reactive Power Demand is expressed in kilovars or kVAr, and Reactive Power Energy is expressed in kilovarhours or kVArh.

49. Reactive Supply and Voltage Control from Generation Sources Service

Reactive Supply and Voltage Control from Generation Sources Service is required to maintain voltage levels on BPA's transmission facilities within acceptable limits. In order to maintain transmission voltages on BPA's transmission facilities within acceptable limits, generation facilities (in the Control Area where the BPA transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on BPA's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BPA. The Transmission Customer must purchase this service from BPA.

50. Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BPA. BPA must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

51. Reliability Obligations

Reliability Obligations are the obligations that a party with resources or loads in the BPA Control Area must provide in order to meet minimum reliability standards. Reliability Obligations shall be determined consistent with applicable NERC, WECC, and NWPP standards. BPA offers Ancillary Services and Control Area Services to allow resources or loads to meet their Reliability Obligations.

52. Reserved Capacity

Reserved Capacity is the maximum amount of capacity and energy that BPA agrees to transmit for the Transmission Customer over the BPA Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Open Access Transmission Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60)-minute interval (commencing on the clock hour) basis. In cases where Dynamic Schedules are involved, the Reserved Capacity must be set at a level to accommodate (i) a demand equal to the largest ten-minute moving average of the load or generation expected to occur during the contract period for one-way Dynamic Schedules used to transfer generation or load from one Control Area to another Control Area; or (ii) a demand equal to the instantaneous peak demand, for each direction, of the supplemental Control Area service request expected to occur during the contract period for two-way Dynamic Transfers used to provide supplemental Control Area services. The supplemental Control Area service response shall always be the lesser of the Control Area service request or the Reserved Capacity associated with the supplemental Control Area service.

53. Scheduled Demand

Scheduled Demand is the hourly demand at which electric energy is scheduled for transmission on the FCRTS.

54. Scheduling, System Control, and Dispatch Service

Scheduling, System Control, and Dispatch Service is an Ancillary Service required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. The Transmission Customer must purchase this service from BPA.

55. Secondary System

As used in the FPT rate schedules, Secondary System is that portion of the Network facilities with an operating voltage greater than or equal to 69 kV and less than 230 kV.

56. Secondary System Distance

As used in the FPT rate schedules, Secondary System Distance is the number of circuit miles of Secondary System transmission lines between the secondary Point of Integration and either the Main Grid or the secondary Point of Delivery (POD), or between the Main Grid and the secondary POD.

57. Secondary System Interconnection Terminal

As used in the FPT rate schedules, Secondary System Interconnection Terminal refers to the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

58. Secondary System Intermediate Terminal

As used in the FPT rate schedules, Secondary System Intermediate Terminal refers to the first and last terminal facilities in the Secondary System transmission path, exclusive of the Secondary System Interconnection terminals.

59. Secondary Transformation

As used in the FPT rate schedules, Secondary Transformation refers to transformation from Main Grid to Secondary System facilities.

60. Short-Term Firm Point-to-Point (PTP) Transmission Service

Short-Term Firm Point-To-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of less than one year. Short-Term Firm Point-To-Point Transmission Service with a duration of less than one calendar day is sometimes referred to as Hourly Firm Point-To-Point Transmission Service.

61. Southern Intertie

The Southern Intertie is the segment of the FCRTS that includes, but is not limited to, the major transmission facilities consisting of two 500-kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500-kV AC line from Buckley Substation to Summer Lake Substation; and the 500-kV AC Intertie facilities, which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000-kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

62. Spill Condition

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

63. Spinning Reserve Requirement

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Spinning Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

64. Station Control Error

Station Control Error is the difference between the amount of generation scheduled from a generator and the actual output of that generator.

65. Super Forecast Methodology

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

66. Supplemental Reserve Requirement

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area. The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

67. Total Transmission Demand

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable agreement.

68. Transmission Customer

A Transmission Customer is any Eligible Customer (or its Designated Agent) under the Open Access Transmission Tariff that (i) executes a Service Agreement, or (ii) requests in writing that BPA file with the Commission a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. In addition, a Transmission Customer is an entity that has executed any other transmission service agreement with BPA.

69. Transmission Demand

Transmission Demand is the maximum amount of capacity BPA agrees to make available to transmit energy for the Transmission Customer over the BPA Transmission System between the Point(s) of Integration/Interconnection/Receipt and the Point(s) of Delivery.

70. Transmission Provider

A Transmission Provider, such as BPA, owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Open Access Transmission Tariff and other agreements.

71. Utility Delivery

The Utility Delivery segment consists of facilities and equipment that transform and deliver energy to a utility's distribution system at (or close to) the utility's prevailing distribution voltage.

72. Variable Energy Resource

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, geothermal, biomass, or process steam generating facilities.

73. Variable Energy Resource Balancing Service

Variable Energy Resource Balancing Service (VERBS) is a Control Area Service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load); following reserves (which compensate for larger differences occurring over longer periods of time during the hour); and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

74. Weekly Service

Weekly Service is service that starts at 00:00 on any date and stops at 00:00 at least seven (7) days later, but less than or equal to 27 days later.

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BONNEVILLE POWER ADMINISTRATION
DOE/BP-4824 • October 2017

PGE

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Re: **UM ____ – PGE's Draft Storage Potential Evaluation**

In accordance with Commission Orders No. 16-504 and 17-118, enclosed is PGE's Draft Storage Potential Evaluation. Attachment A is the Draft Storage Potential Evaluation, designed to meet the guidelines outlined in Order 17-118. Attachment B is PGE's Summary of Energy Storage Request for Information (RFI), designed to meet item 2.g. in the Storage Potential Evaluation Guidelines set forth in Order No. 16-504.

To provide broader context for the study included as Attachment A, this letter outlines how PGE proposes to use this evaluation to propose energy storage projects to the OPUC, and summarizes the strengths and shortcomings of the three primary models used to inform the evaluation.

This evaluation in the context of UM 1751

The study provided herein demonstrates the potential benefits of different energy storage systems interconnected with PGE's electric system at various locations (i.e., storage "use cases"). The study does not identify or even contemplate potential costs of the storage systems required for each use case. Cost information will be included in the final evaluation submitted in concert with PGE's proposal of specific storage projects.

Importantly, the costs required to achieve the benefits outlined in the attached study go beyond the cost of the storage system itself, i.e., the cost of engineering, procuring and constructing the storage system. In some cases, achieving the benefits identified require whole system upgrades – for example, to achieve the power reliability benefits identified for storage located at customer sites requires site-specific engineering studies, site upgrades, and commissioning to enable the customer to effectively island some or all of its load from the grid during an outage. Another example is the need for energy storage communications and control platforms that enable PGE to automate and optimize dispatch of aggregated storage systems across the system in order to realize many of the benefits described. These broader system upgrades might provide broader benefits to PGE than those related to the storage project itself. For example, storage control platforms can provide learning and early frameworks that might enable broader benefits from other smart grid projects, like demand response and conservation voltage reduction.

Moreover, simply comparing the quantified benefits of storage systems to their total costs will not be sufficient for determining the most valuable storage projects for PGE to pursue in context of UM 1751. Consistent with OPUC Order No. 16-504, PGE plans to propose "a portfolio of projects that balance technology maturity, technology potential, short- and long-term project performance and risks, and short- and long-term potential value." Doing so presents the best opportunity to pursue projects that offer the greatest potential benefits for PGE customers.

Strengths and shortcomings of ROM, IPT, and NVEST

From a high level, the science and art of evaluating the potential for energy storage is nascent. Tools exist to do this work, but they are all in their early stages and will continue to evolve as the industry understanding and operational experience with energy storage systems mature. PGE has learned a tremendous amount about the potential of energy storage to serve grid needs from its Salem Smart Power Center. Such real-world examples, however, are too few and have thus far provided too little operational data to fully validate the work that the evaluation models used by Navigant and others attempt.

As the attached study describes in more detail, Navigant primarily relied upon three models to determine the benefits of the storage use cases. Two of these models – the Resource Optimization Model (ROM) and the Integrated Planning Tool (IPT) – are PGE models that historically have served other purposes and have been amended to evaluate energy storage. The Navigant Valuation of Energy Storage Tool (NVEST) took inputs from ROM, IPT, and other data sources (PGE data or typical industry values) to determine the potentially monetizable value of various storage applications and use cases. Each of the three primary models – ROM, IPT, and NVEST – used for the evaluation have their relative strengths and shortcomings, as described below.

<u>ROM</u>

ROM –first used to model energy storage in the 2016 IRP – is generally considered a best-in-class approach to identifying the benefits of introducing energy storage into a utility's total resource portfolio. PGE's ROM methodology was highlighted in the Energy Storage Association's 2016 primer on energy storage modeling in IRPs, and PGE was invited to present the analysis at industry and policy forums, including the Western Energy Institute's Integrated Resource Planning Forum and the North Carolina Sustainable Energy Association's Energy Storage Working Group. Moreover, at a May 24th Pacific Coast Distributed Energy Summit, Staff from the California PUC indicated that they were urging the utilities in California to essentially adopt a ROM-like approach to determine the benefits of energy storage to a utility's existing resource portfolio.

ROM has, however, two meaningful drawbacks. The first is that in order to actually identify overall benefits to storage, the storage system must be large – at least 50 MW (larger than the cap in HB 2193). Accordingly, the enclosed study assumed that the benefits ROM identified for a 50 MW system scale perfectly to systems of smaller sizes. This assumption may or may not be true.

A second complicating factor is that ROM holistically looks at how a total portfolio of resources acts to provide all of the following services: energy arbitrage, regulation, load following, and spinning/non-spinning reserves. ROM looks at one portfolio without storage and then an identical portfolio with storage. The improved performance of the latter portfolio represents the operational value of the storage system. The identified benefits encompass all of the applications listed above, accounting for the fact that operational decisions to provide one application necessarily have implications for the ability of the system to provide other applications. While this framework captures the total potential operational value, it does not lend itself easily to parsing individual operational benefits. As detailed in the attachment, PGE did some additional analysis to attempt to better isolate values of the unique energy and ancillary services captured by ROM, but such work is preliminary.

IPT

The IPT – a project valuation tool co-developed by PGE and BIS Consulting – is typically used to calculate and compare the economic merit of T&D system investments in different parts of PGE's service area. The IPT does this by comparing the cost of proposed T&D investments to their benefit. The benefit is calculated by determining the reduced risk of an outage to a customer.

The IPT draws on an array of foundational risk models used by T&D's Strategic Asset Management group (SAM) for long-range risk management planning. SAM calculates "risk" from the customer's perspective. In other words, while "risk" includes the direct costs of an outage to PGE and the cost of asset replacement (if required), the primary driver of risk in the T&D system is the economic impact of an outage on customers should an outage occur. Thus, the drivers of risk in the T&D system include the likelihood of an outage, the duration of an outage should an outage occur, the load affected in an outage, and the economic impact of the outage on the residential, commercial, and industrial customers that have lost power.

For this analysis, SAM's IPT tool was slightly modified to identify the best locations for energy storage; rather than calculating a benefit/cost ratio (which requires a cost input), the IPT simply looked at the reduction in baseline risk that was achievable should a battery be placed in the array of system locations identified for analysis (at the substation, on the feeder, etc.). The goal was to ascertain where in the system a reduction in outage duration would have maximum risk reduction benefit – in other words, where in PGE's system customers would most benefit from the outage mitigation benefits of a storage investment.

For substation and feeder-sited energy storage systems, this risk reduction benefit was interpreted as a potential avoided cost because it theoretically provides the opportunity to defer or avoid other investments in the distribution system. Importantly, these distribution benefits estimated in the report are based on statistical analysis over a large number of locations on the grid and are not representative of specific sites. Potential distribution benefits at specific sites will depend on the infrastructure, risks, and operational considerations at that specific site. For customer-sited systems in the report, the risk reduction benefit is interpreted as an individual customer benefit because those systems are modeled as behind-the-meter for simplicity. Installations at customer sites that are in front of the meter may blend distribution and utility customer benefits, but such determinations would be highly site- and configuration-specific.

Analysis of the benefits of energy storage in the distribution grid at other utilities has focused on identifying specific transformers or other distribution assets for which replacement due to load growth can be deferred. Such an approach was deemed insufficient for this analysis because of PGE's load growth profile. Within our territory, load growth tends to be clustered, meaning it is sudden and significant (e.g., a new server farm). Typically, this type of growth requires the installation of significant new infrastructure that could not be deferred through the installation of energy storage alone. Moreover, there are no incremental upgrades pending in PGE's system for which energy storage was deemed an adequately reliable and appropriate alternative to asset replacement.

To our knowledge, this evaluation is the first attempt to use such an approach to identify the distribution-level benefits of energy storage. PGE has received generally positive feedback from a number of stakeholders – including those well-versed in energy storage modeling – on the use of the IPT for this purpose. Our hope is that this approach to identifying the outage mitigation benefits of energy storage will be as appreciated as the use of ROM to identify energy and ancillary service benefits.

One drawback of the use of the IPT for this analysis is that it was built to compare the relative merits of projects across the T&D system as opposed to calculating the financial value of a specific project installation. Put another way, the values used to calculate outage impact costs to customers are not customer-specific; rather, they were taken from a generalized study of average outage costs to customers at the customer-class level (residential, commercial, industrial). In suit, the IPT is useful for determining the outage mitigation benefits of energy storage to a large number of customers, but when energy storage is located at a specific customer site to provide a power reliability benefit, generalized outage costs may not accurately represent the value these customers place on reliable power. In short, while the IPT outputs have been used to calculate posited power reliability benefits for customers, specific customers might (and likely will) value battery installation differently than calculated by the IPT. As such, the power reliability benefits identified in this report should be considered illustrative, not indicative.

NVEST

Finally, Navigant's NVEST model was used to combine inputs from ROM, IPT and other data sources and optimize different storage use cases. This model was used previously by, among others, five California utilities for compliance with the requirements of AB 2514, which established energy storage procurement targets. As desired by most stakeholders, the model is well established and transparent.

PGE appreciates the opportunity presented by HB 2193 and UM 1751 to continue to investigate energy storage. We believe that the attached evaluation represents an important next step toward understanding the potential benefits of energy storage to the system. At the same time, PGE acknowledges that energy storage technologies and deployments are still immature relative to more established grid technologies, as are the modeling tools used to evaluate them.

PGE is committed to continuing to refine its own modeling capabilities and to take advantage of continued improvements in third party tools over time. Perhaps more importantly, PGE looks forward to gaining more operational experience through the procurement of energy storage resources. This knowledge will help PGE to improve the understanding and evaluation of energy storage resources in its system and prepare for the deployment of cost effective energy storage resources at larger scales.

If you have any questions or require further information, please call me at (503) 464-8954. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Robert Macfarlane
Regulatory Affairs

cc: Jason Salmi Klotz, OPUC

Energy Storage Potential Evaluation

Prepared for:

Portland General Electric

Oregon Public Utilities Commission Docket – UM 1751

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EXECUTIVE SUMMARY

This Draft Energy Storage Potential Evaluation report has been prepared by Navigant for Portland General Electric (PGE) in compliance with the requirements set forth by Oregon House Bill 2193 (HB 2193) and Docket UM 1751.

This report contains the results of analysis of the expected benefits to PGE's system and to individual customers resulting from deploying energy storage systems at different locations on PGE's network (e.g., transmission, distribution, and customer level) for different grid applications (e.g., energy arbitrage, load following, demand charge reduction). Under the specific conditions evaluated across a variety of different use cases, the results indicate that system benefits (socialized benefits that are distributed across all customers) vary from roughly $200/kW to more than $2,300/kW on a net present value (NPV) basis, while individual customer benefits (those that accrue only to one specific customer range from $0/kW to more than $2,400/kW. These benefits will be considered in light of energy storage system (ESS) costs in the Final Energy Storage Potential Evaluation, which will evaluate proposed deployments of energy storage systems at specific locations on PGE's network.

Section 1 introduces the requirements set forth by HB 2193 and UM 1751 and their relation to the content contained herein and to the approach used to evaluate the potential benefits of energy storage within PGE's territory. This information provides context for understanding the chosen methodology, which is described in Section 2. Appendix A provides further supporting information, identifying how the approach complies with requirements set forth within HB 2193 and UM 1751.

Section 2 provides an overview of the methodology used to evaluate storage potential, including the high level approach, the models used, the use cases considered, and the approach for considering various technologies. This section provides context to understand and interpret the results provided in Section 3. The approach considers all applications explicitly specified by the Oregon Public Utility Commission (OPUC). Various models and inputs were used to assess the value of individual applications. The PGE Resource Optimization Model (ROM) generated values for energy and ancillary services benefits by optimizing the use of energy storage in combination with PGE's generation fleet. The PGE Integrated Planning Tool (IPT) generated values for using energy storage as backup power to reduce the cost of maintaining distribution infrastructure and to reduce customer impacts resulting from network outages. A variety of PGE inputs and typical industry parameters were used to determine the value of all other applications, such as the benefits from deferred transmission investments.

The Navigant Valuation of Energy Storage Tool (NVEST)—which uses a framework that was initially developed for the US Department of Energy and has been peer-reviewed by industry stakeholders—was used to assess the value of five different use cases of energy storage:

(1) A 20 MW transmission-level ESS

(2) A 10 MW ESS at a distribution substation

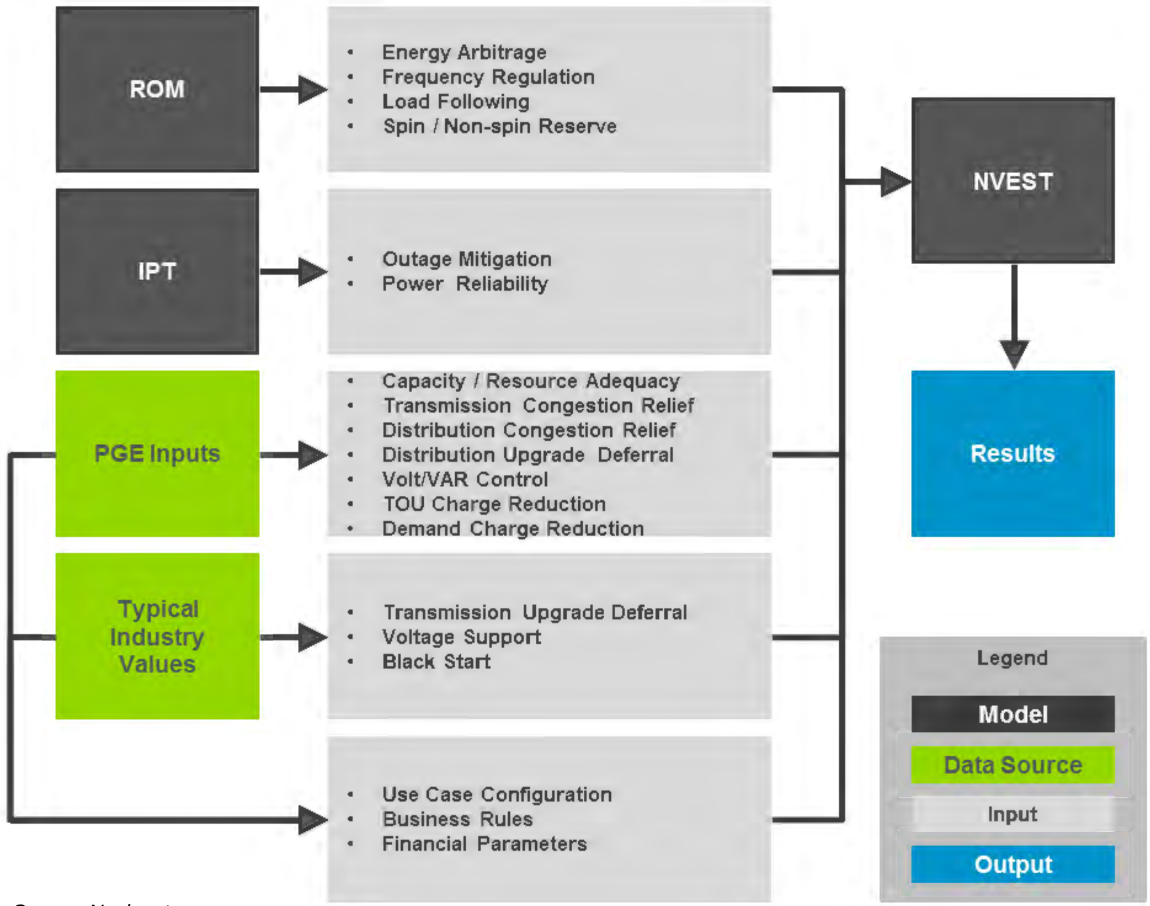
(3) A 2 MW ESS along a distribution feeder

(4) 1 MW of aggregated ESSs located at medium and large commercial and industrial (C&I) customer sites

(5) 1 MW of aggregated ESSs located at residential and small C&I customer sites

Figure 1 summarizes the modeling approach.[1]

Figure 1-1. Modeling Approach



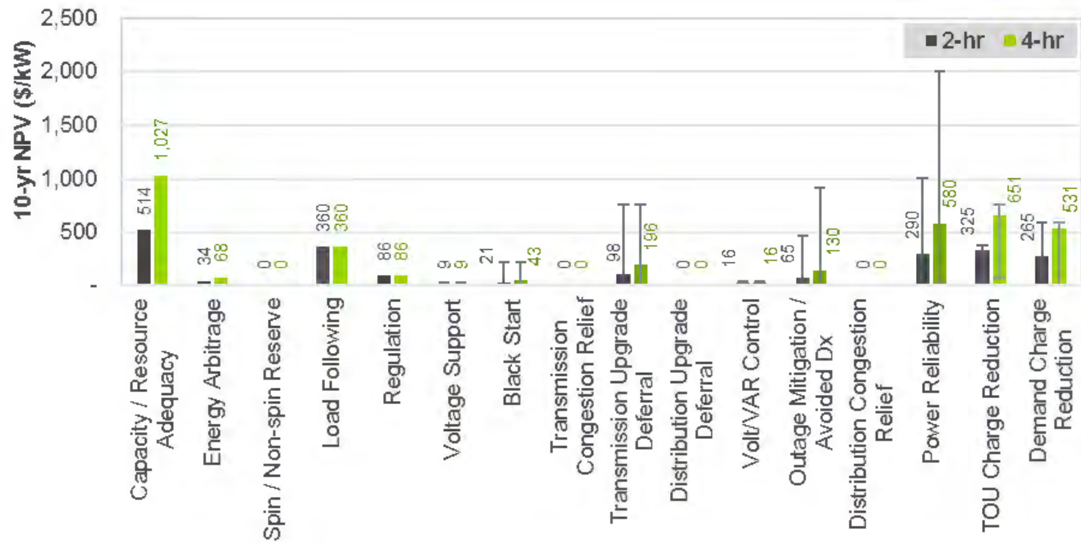
Source: Navigant

Within a given use case, different scenarios were considered with different ESS durations (i.e., 2 hour and 4 hour), as well as different business rules for determining how the ESSs would be dispatched to serve multiple applications.

Section 3 provides the results of the analysis. First, benefits were evaluated for individual applications (Figure 2). These results helped to guide the use case configuration, as applications were selected for each use case based upon their benefit values and their compatibility with one another. Low value applications were not included in the use cases.

[1] Appendix B provides additional details regarding the ROM, IPT, and NVEST models.

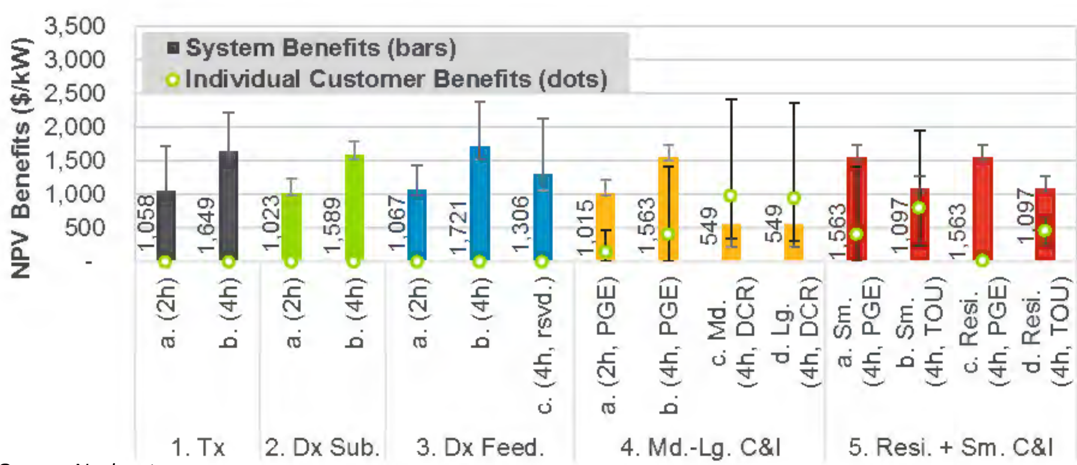
Figure 1-2. 10-year Benefits of Each Application[2]



Source: Navigant

The analysis for each use case provides a summary of the benefits under each of the associated scenarios, including results under low, base, and high conditions. These conditions help to provide an indicative range of potential benefits due to variability associated with particular benefit streams (e.g., differences in the cost of deferred transmission capacity and the period over which investments may be deferred). The range of potential system benefits is similar between use cases to the range between different scenarios within the same use case (Figure 3). Accordingly, the duration of the ESS and the business rules for dispatch are just as important of considerations as the location of the ESS on PGE's network.

Figure 1-3. Summary of Results for all Use Cases

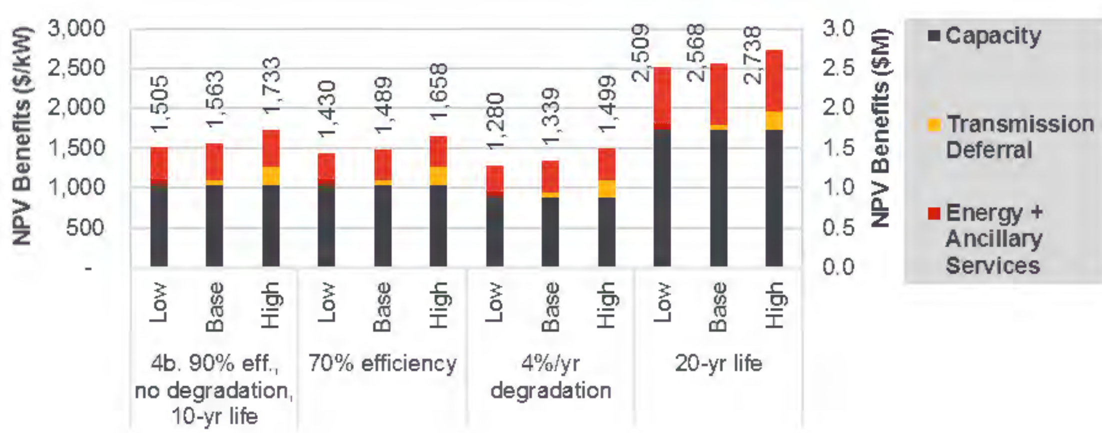


Source: Navigant

[2] Error bars are provided only for applications with significant uncertainty/variability in benefits.

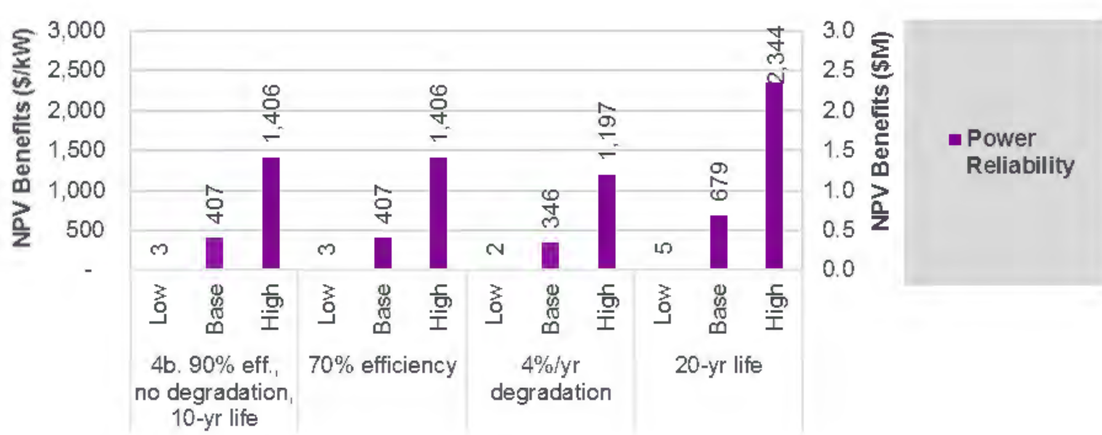
The analysis is intentionally technology-agnostic, as PGE intends to consider bids from a variety of different technologies when procuring ESSs. Key parameters associated with storage technologies (including efficiency, degradation rate, and lifetime) can vary significantly not only between different types of technologies (e.g., Li-ion vs. flow) but also within a family of technologies (e.g., Li-ion batteries from different suppliers). Thus, to evaluate the impact of technology, the analysis focused on the impact of specific parameters rather than assumed parameters associated with different technologies (Figure 4 and Figure 5). Round-trip efficiency was found to have a modest impact on the results. While round-trip efficiency can have a significant impact for value streams requiring frequent charge and discharge (e.g., energy arbitrage, load following, regulation), many of the benefit streams only require occasional dispatch (e.g., capacity, transmission deferral, outage mitigation). Degradation of the technology over time reduces the available power and energy capacity available to support different applications, which can reduce the net present of benefits by 15% or more. Extending the lifetime of the technology can have a profound impact on the results. A 20-year ESS was found to produce over 60% greater NPV benefits relative to a 10-year ESS. This result is largely tied to PGE's relatively low cost of capital.

Figure 1-4. Impact of Technology Parameters on System Benefits



Source: Navigant

Figure 1-5. Impact of Technology Parameters on Individual Customer Benefits



Source: Navigant

This analysis provides a foundation for PGE to consider specific deployments of energy storage at specific locations on its network, which will be considered and assessed in the Final Energy Storage Potential Evaluation report.

1. INTRODUCTION

Oregon House Bill 2193 (HB 2193) requires Portland General Electric Company (PGE) to submit a proposal to develop energy storage systems (ESSs) and to procure any authorized projects by January 1, 2020. The Oregon Public Utility Commission (OPUC) UM 1751 sets guidelines and requirements for the implementation of HB 2193, including a requirement to deliver a draft storage potential evaluation. This report presents Navigant's storage potential evaluation findings.

This section provides an overview of the requirements for the evaluation, which were set forth by HB 2193 (Section 1.1) and the resulting proceedings in Docket UM 1751 (Section 1.2), including the specific applications of energy storage to be considered in this analysis (Section 1.3). This information provides context for understanding the chosen methodology, which is described in Section 2. Appendix A provides further details regarding individual requirements for the potential evaluation and the compliance of this analysis with those requirements.

Section 2 provides an overview of the methodology used to evaluate storage potential, including the high-level approach, the models used, the use cases conducted, and the approach for considering various technologies. This section provides context to understand and interpret the results provided in Section 3. The results include benefits associated with individual applications, the benefits associated with using the ESS for multiple applications within a given use case, and the impact of technology parameters on those benefits.

1.1 HB 2193

HB 2193[3] directs large Oregon electric companies, including PGE, to submit proposals for qualifying ESSs with the capacity to store at least 5 MWh of energy. The bill caps the total capacity of the ESSs procured by each electric company at one percent of the company's peak load in 2014, with an exception for a project of statewide significance. The electric companies adopted proposal guidelines by January 1, 2017 and must submit ESS proposals by January 1, 2018.

HB 2193 outlines several requirements for the energy storage proposals:

1. Each proposal must be accompanied by a comprehensive evaluation of the potential to store energy in the electric company's system.
2. Specific analysis must be provided in the proposal including technical specifications for the project, the estimated cost, and the benefits to the electric grid.
3. Each proposal must be evaluated to determine whether it: (a) is consistent with the guidelines; (b) reasonably balances the value for customers, utility operations, and the costs of construction, operation, and maintenance; and (c) is in the public interest.

The following report presents Navigant's storage potential evaluation to determine the potential value of energy storage systems at different locations on PGE's system. If the OPUC authorizes a storage project, the electric company has until January 1, 2020 to procure the qualifying ESS. HB 2193 specifies that the electric companies may recover in rates all costs prudently incurred in procuring qualifying ESSs under this program, including any above-market costs associated with procurement.

[3] House Bill 2193, https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193.

1.2 UM 1751

UM 1751[4] sets the guidelines and requirements for the implementation of HB 2193 by adopting the following:

1. Project guidelines to help the electric companies design and select projects to propose for development.
2. Proposal guidelines for the electric companies to submit proposals for authorization.
3. Storage evaluation requirements to help electric companies conduct the mandated system-wide storage potential evaluation.
4. Competitive bidding requirements for HB 2193 programs.

This report achieves compliance with third item, requiring that electric companies file a draft system-wide storage evaluation with the OPUC. The Storage Potential Evaluation includes an analysis of operations and system data, an examination of how storage would complement the electric company's existing action plans, and identification of areas with opportunity to partner with customers for the use of energy storage at their locations. Evaluation requirements for this study are provided in Appendix A.

This report represents PGE's draft system-wide storage evaluation. The electric companies will file final versions of their evaluations with their formal project proposals by January 1, 2018.

1.3 Potential Evaluation Requirements

The March 21, 2017 public meeting staff report[5] outlines the applications for consideration in the draft system-wide storage evaluation. These applications are provided in Table 1-1 and evaluated in the following energy storage potential study. Appendix A provides tables that detail how the evaluation framework, key evaluation elements, and modeling attributes map to the requirements set forth by the OPUC.

Table 1-1. OPUC Storage Applications Evaluated[6]

Category	Application	Description
Bulk Energy	Capacity/ Resource Adequacy	The ESS is dispatched during peak demand periods to supply energy and shave peak demand. The ESS reduces the need for new peaking power plants.
	Energy Arbitrage	Trading in the wholesale energy markets by buying energy during low-price periods and selling it during high-price periods.

[4] UM 1751, Implementing Energy Storage Program Guidelines pursuant to House Bill 2193, http://apps.puc.state.or.us/orders/2016ords/16-504.pdf.

[5] Public Utility Commission of Oregon Staff Report, Implementing an Energy Storage Program – Staff Report Pursuant to Order No. 16-504, http://apps.puc.state.or.us/orders/2017ords/17-118.pdf.

[6] Application descriptions reflect the language in the OPUC Staff Report and do not necessarily reflect PGE's or Navigant's definitions of these grid services for PGE specifically. PGE operates its system consistent with all applicable NERC/WECC standards.

Category	Application	Description
Ancillary Services	Regulation	An ESS operator responds to an area control error to provide a corrective response to all or a segment portion of a control area.
	Load Following	Regulation of the power output of an ESS within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.
	Spin/ Non-spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is offline generation capable of being brought onto the grid and synchronized to it within 30 minutes.
	Voltage Support	Voltage support consists of providing reactive power onto the grid to maintain a desired voltage level.
	Black Start	Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
Transmission Services	Transmission Congestion Relief	Use of an ESS to store energy when the transmission system is uncongested and provide relief during hours of high congestion.
	Transmission Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage or avoiding the purchase of additional transmission rights from third-party transmission providers.
Distribution Services	Distribution Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the system to accommodate load growth or regulate voltage.
	Volt/VAR Control	In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power in an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity.
	Outage Mitigation	Outage mitigation refers to the use of an ESS to reduce or eliminate the costs associated with power outages to utilities.
	Distribution Congestion Relief	Use of an ESS to store energy when the distribution system is uncongested and provide relief during hours of high congestion.
Customer Energy Management Services	Power Reliability	Power reliability refers to the use of an ESS to reduce or eliminate power outages to utility customers.
	TOU Charge Reduction	Reducing customer charges for electric energy when the price is specific to the time (season, day of week, time of day) when the energy is purchased.
	Demand Charge Reduction	Use of an ESS to reduce the maximum power draw by electric load to avoid peak demand charges.

Source: Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

2. METHODOLOGY

This section summarizes Navigant's methodology for conducting the storage potential evaluation as required by OPUC UM 1751. The following sections provide detail on key aspects of the analysis, including:

- Storage potential evaluation approach
- Models and data sources used for the analysis
- Use cases evaluated
- Energy storage technologies considered

Section 2.1 describes the general approach used to determine the value of each individual application. Section 2.2 describes the models and data sources used in the analysis, along with other inputs and assumptions. Section 2.3 first describes the considerations used in determining how to construct the use cases, then describes the inputs and assumptions associated with each use case. Next, Section 2.4 describes the technology parameters associated with the use case analysis (results in Section 3.2), as well as the approach to analyzing the impact of technology on benefits (results in Section 3.3).

2.1 Storage Potential Approach

Navigant determined the typical benefits for each of the applications reflected in the Oregon framework established by the Commission in the March 21, 2017 stakeholder meeting. Our analysis includes values that reflect PGE-specific information to the extent possible. As described in Section 3.1, benefit values may vary within or between use cases, and not all benefits accrue to the same entity. Some applications provide system benefits to PGE (which are socialized across customers), while others provide individual customer benefits to single customers.

Table 2-1. Storage Potential Valuation Methodology by Application

Category	Application	Methodology & Data Sources
Bulk Energy	Capacity/ Resource Adequacy	Calculated as the net cost of a new Generic Capacity resource, consistent with the 2016 IRP. This capacity value is applied to the maximum discharge power that can be sustained for 4 hours.
	Energy Arbitrage	Determined from an energy-only energy storage dispatch simulation with 15-min prices from the 2016 IRP Reference Case. This represents the value of Energy Arbitrage in the absence of ancillary service opportunities.

Category	Application	Methodology & Data Sources
Ancillary Services	Spin/ Non-spin Reserve	While the total operational value used in this evaluation is inclusive of the ability to provide contingency reserves, the Resource Optimization Model (ROM) analysis suggests that the value of providing additional contingency reserves is very small relative to other operational applications. Thus this value is assumed to be negligible. See Appendix B for more information.
	Load Following	Determined by comparing ROM results with Energy Arbitrage, Spin / Non-spin Reserve, and Load Following to the isolated Energy Arbitrage value. This value represents the marginal benefit of adding Load Following to the application stack after Energy Arbitrage and Spin/ Non-spin Reserve. Note that the value does not represent the value of performing Load Following alone, and the value is dependent upon the order in which applications are added to the stack. Load Following is inclusive of forecast error mitigation and sub-hourly flexibility down to five minutes. See Appendix B for more information.
	Regulation	Determined from ROM results. This value represents the marginal benefit of adding Regulation to the application stack after Energy Arbitrage, Spin/ Non-spin Reserve, and Load Following. Note that the value does not represent the value of performing Regulation alone, and the value is dependent upon the order in which applications are added to the stack. See Appendix B for more information.
	Voltage Support	Navigant looked at typical market values in wholesale for this service where voltage support markets exist. However, the value is effectively zero for PGE, as the Reactive Demand Program with the Bonneville Power Administration was discontinued in 2014, and PGE no longer pays reactive demand charges. Thus PGE does not have a need for additional Voltage Support services.
	Black Start	Navigant looked at typical market values for this service where Black Start markets exist. However, the value is effectively zero for PGE, as it does not have a need for additional Black Start services. To comply with the EOP-005 NERC Compliance Standard, PGE maintains an official Black Start plan which includes the existence of adequate resource to provide Black Start capability. The introduction of new energy storage resources (distributed or other) would not be considered as a replacement for PGE's existing Black Start resource.
Transmission Services	Transmission Congestion Relief	At present, PGE transmission system modeling suggests limited congestion issues on its transmission system, leading to no meaningful basis to monetize benefits.
	Transmission Upgrade Deferral	This value is based upon representative capital costs of transmission ($125/kW) assuming a 1-year deferral period with 2% inflation, a fixed charge rate of 8%, and an ESS with 5% of the capacity (kW) of the transmission equipment being deferred.[7]

[7] T&D Upgrade Deferral. Energy Storage Association. http://energystorage.org/energy-storage/technology-applications/td-upgrade-deferral.

Category	Application	Methodology & Data Sources
Distribution Services	Distribution Upgrade Deferral	Opportunities for distribution investment deferrals on the PGE system are primarily driven by aging infrastructure for two reasons. Historically, PGE has constructed a distribution system to reliably serve all customers during peak loading conditions, even when a single asset is out of service (i.e., N-1 redundancy). Secondly, at present new load growth tends to be caused by significant commercial or industrial demand that is inherently clustered (e.g., a server farm), requiring significant new infrastructure. PGE prioritizes investments in distribution system upgrades based on a probabilistic analysis of potential component failure. The value of potential avoided distribution investments is encompassed within the Outage Mitigation category. The method is described more fully in Section 2.2.3.
	Volt/VAR Control	This value is representative of a recent investment in Volt/VAR equipment by PGE and reflects an avoided cost in similar equipment.
	Outage Mitigation	The values were calculated using the Integrated Planning Tool (IPT), as described in Section 2.2.3, and are representative of avoided investments in distribution infrastructure. The model outputs, which reflect the NPV over an infinite period, were adjusted to reflect 10-year benefits.[8] These values vary significantly depending on the location of the ESS, and different ranges of values were calculated at the substation level and feeder level.
	Distribution Congestion Relief	PGE does not have significant congestion issues on its distribution system, so there is no meaningful basis from which to monetize benefits.
Customer Energy Management Services	Power Reliability	Power Reliability benefits were calculated in a similar fashion to the Outage Mitigation benefits (see above), but these benefits are specifically for customer-sited systems and applied only to a single customer. The benefits are based upon customer value of service ranges, which were generated from surveys and used as inputs in the IPT model, as described in Section 2.2.3.
	TOU Charge Reduction	The range was calculated based upon the margin between peak and off-peak retail price of electricity for rate schedules 7, 32, 83, and 85.[9] The analysis assumes one cycle per weekday with 90% round-trip efficiency.
	Demand Charge Reduction	The range was calculated based upon monthly demand charges per kW for rate schedules 7, 32, 83, and 85.

Source: Navigant

2.2 Models

Figure 2-1 summarizes the modeling approach utilized in this analysis. The Navigant Valuation of Energy Storage Tool (NVEST) was used to run each of the use cases described in Section 2.3. The inputs and assumptions for the NVEST model were determined from a variety of sources:

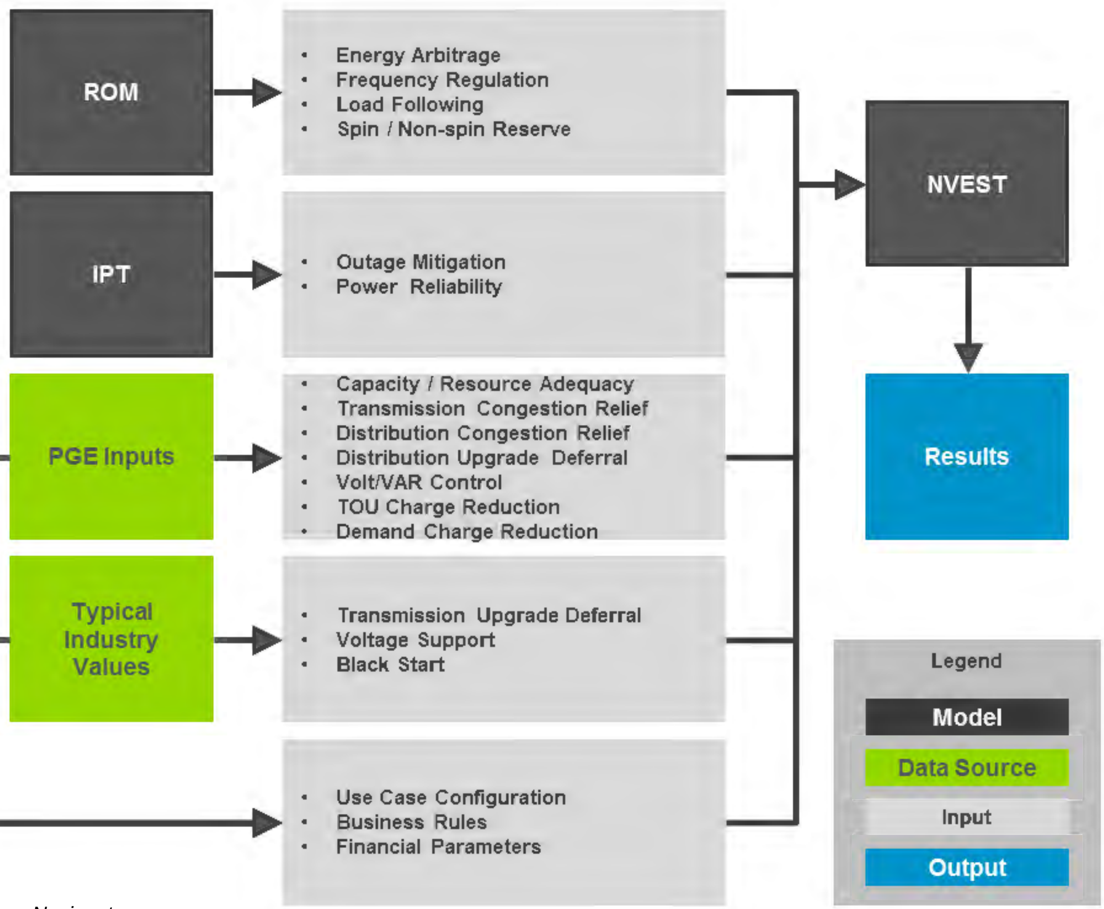
- ROM was used to determine the co-optimized value of energy arbitrage, regulation, Load Following, and Spin/Non-spin Reserve (see Section 2.2.2 below).
- IPT was used to determine the value of Outage Mitigation (inclusive of avoided distribution investments) and Power Reliability benefits as described in Section 2.2.3.

[8] According to BIS Consulting, which performed the IPT analysis, the 10-year value is approximately 70% of the infinite-life value.

[9] Rate schedules 7, 32, 83, and 85 are representative of residential, small C&I, medium C&I, and large C&I customers, respectively.

- PGE provided input values for Transmission Congestion Relief, Distribution Upgrade Deferral, Distribution Congestion Relief, Volt/VAR Control, TOU Charge Reduction, and Demand Charge Reduction (DCR) as indicated in Table 2-1.
- Typical industry values were obtained for Transmission Upgrade Deferral, Voltage Support, and Black Start (Table 2-1).
- The use case configuration (including the size, location, applications, etc.), business rules and assumptions for dispatching the ESS, and the financial parameters (e.g., escalation rates, cost of capital, lifetime) were developed in coordination with PGE and informed by representative industry values and assumptions (see Section 2.3).

Figure 2-1. Modeling Approach



Source: Navigant

2.2.1 Navigant Valuation of Energy Storage Tool

NVEST is based upon a tool originally developed by Navigant in 2008 for the US Department of Energy (DOE) to evaluate the potential of energy storage in various grid applications across the United States. The comprehensive framework provides a methodology that maps applications to benefits with monetized values (Figure 2-2). This framework was later peer-reviewed, evaluated by many industry stakeholders, and adopted by the DOE for use by the recipients of the Smart Grid Demonstration program. A detailed description of the basic methodology is publicly available online.[10]

Figure 2-2. NVEST High-level Framework

Source: Navigant

Since 2008, Navigant has built upon this framework using the Excel-based NVEST model to execute our framework and valuation methodology, resulting in a net present value (NPV) analysis. This framework has been used to support regulatory filings by other utilities, including five utilities in California for compliance with the requirements of AB2514.[11]

Appendix B provides greater detail regarding the NVEST model and the associated methodology and assumptions for the analysis described in this report.

2.2.2 Resource Optimization Model

ROM is a multi-stage production simulation model of PGE's resource portfolio. PGE described ROM and its application to energy storage resource evaluation in Chapter 8 of PGE's 2016 Integrated Resource Plan (IRP).[12] ROM was originally designed to quantify operational challenges and costs associated with renewables integration. Because of this history, ROM already incorporated the key features required for quantifying the operational value of energy storage resources: optimal unit commitment and dispatch of the PGE resource fleet over multiple time horizons, impacts of forecast errors (e.g., day-ahead to real-time), ancillary service requirements, and sub-hourly dispatch.

ROM simulations allow for the estimation of the operational value of energy storage resources that are operated in a coordinated manner within PGE's resource fleet. Operational value streams include: energy arbitrage, load following, regulation, spinning, and non-spinning reserves. ROM does not address capacity value, values for other services at the transmission, distribution, and customer levels, or the interactions between operational and non-operational value streams.

[10] DOE Energy Storage Computational Tool Overview. US Department of Energy. August 2012 https://www.smartgrid.gov/document/doe_energy_storage_computational_tool_overview.html.

[11] AB 2514 Energy Storage System Procurement Targets from Publicly Owned Utilities. California Energy Commission. http://www.energy.ca.gov/assessments/ab2514_energy_storage.html (Azusa Light and Water, City of Banning, City of Pasadena, Riverside Public Utilities, and City of Vernon).

[12] Additional information about the development of ROM can be found in Section 7.2.1.1 in PGE's 2016 IRP.

For the Energy Storage Potential Evaluation, PGE updated energy price assumptions and evaluated three configurations, including: 50-MW 2-hour, 4-hour, and 6-hour ESSs, each with 90% round-trip efficiency. For each of these configurations, a ROM simulation yielded the operational cost of meeting loads and ancillary service requirements across a test year (2021) with and without the ESS. The operational value of the ESS is calculated as the cost difference between these two simulations. This approach optimizes across the energy and ancillary service value streams in order to provide a single number that represents their combined value. Additional information about the ROM modeling approach and the simulations conducted to support the Energy Storage Potential Evaluation can be found in Appendix B.

2.2.3 Integrated Planning Tool

IPT provides a life-cycle analysis of the Outage Mitigation benefits (via extended life of PGE assets) and Power Reliability benefits (via avoided outage costs to individual customers) associated with ESSs located at the substation, feeder, and customer level. The tool was developed by the Strategic Asset Management group (SAM) at PGE and BIS Consulting. The analysis was executed by representatives from T&D Planning, SAM, and BIS Consulting.

IPT and other life-cycle cost tools quantify customer and company risks due to service failures, including the cost of future asset replacements, and the economic costs incurred by customers due to a loss of power. The cost of outages to customers is calculated based on study and survey data of the value of reliable electrical service to customers; these same values are used by SAM in all of its risk analyses. The inputs estimate an expected impact cost to customers for each customer class evaluated due to a loss of power. In other words, all residential customers are assumed to have the same outage impact cost, per kilowatt-hour, as are all commercial customers and all industrial customers. System data was used to determine the average annual load, by customer class, for each grid location analyzed. The system disturbance database and the outage management system were then used to evaluate outage frequency at different grid locations. The benefit of battery installation was calculated as the avoided risk cost to customers and PGE—primarily due to outage avoidance or duration reduction—due to the battery installation.

All substations and feeders were evaluated to assess distribution system benefits. For analysis of individual commercial and industrial (C&I) customers, a sample of customers were selected from grid locations expected to have relatively high value. Thus, the base values provided for C&I customer-sited ESSs are greater than system-wide averages.

The results are expressed in NPV, assuming replenishment/replacement of batteries to maintain constant capacity over time in perpetuity. To evaluate ESSs with a finite life, the 10-year NPV was assumed to be 70% of the infinite-life value based upon the discount rate and other assumptions used in the analysis.

Because PGE uses outage risk to prioritize distribution investments through the IPT, the IPT can be used both to estimate system benefits associated with Outage Mitigation (including avoided distribution investments), as well as to estimate individual customer benefits associated with improved Power Reliability for a customer-sited ESS. These different benefit streams are described below in Section 2.2.3.1 and 2.2.3.2 respectively.

2.2.3.1 System Benefits: Outage Mitigation / Avoided Distribution Investments

To compute the value of upgrading distribution infrastructure, the IPT multiplies the likelihood of a distribution component failing by the cost of the outage to the affected customers. This method works for distribution projects at the feeder and substation level, which affect many customers (sometimes thousands), because the cost of the outage to affected customers uses averages from reliable survey data and analysis. In the face of the need to replace distribution equipment, the method both prioritizes which projects should be done first and provides a quantitative benefit/cost ratio. For applications at the feeder and substation level, these benefits flow to all customers because benefits associated with avoided distribution investments are socialized. In other words, these are system benefits when the ESS is located at the feeder or substation level. This specific benefit stream is hereon referred to as Outage Mitigation/ Avoided Distribution Investments or Outage Mitigation/ Avoided Dx.

2.2.3.2 Individual Customer Benefits: Power Reliability

The same methodology (probability of outage times cost to affected customers) is used in this evaluation to approximate the Power Reliability benefits for customers with customer-sited ESSs.[13] This evaluation uses average customer outage costs – based on survey data – in order to assign a value to Power Reliability benefits at a general level. The actual cost of an outage for a specific customer will vary significantly from aggregate average outage costs derived from survey data. The only way to know the actual cost of an outage to a specific customer is to ask the customer or to offer increased reliability at a given price and to see if that customer is willing to purchase it. The Power Reliability values used in this report should be taken as one approach to estimating a customer benefit that varies widely from one customer to another; these values should not be assumed to equate to the actual value of Power Reliability to any specific customer.

2.3 Use Cases

Navigant's analysis evaluated the value of different applications in PGE's service area across five different use cases (specific combinations of grid location, energy storage power rating, and stacked applications). Within a given use case, different scenarios were considered with different durations (i.e., 2 hours and 4 hours), as well as different business rules for ESS dispatch.

To determine the appropriate set of stacked applications and business rules for each use case, Navigant considered four criteria:

- **Location:** Whether a storage application can be performed at all locations on the grid (transmission, distribution, and customer) or only at certain locations
- **Duration:** The minimum duration required for storage to provide application value (≤2 hours to 4 hours)

[13] While customer-sited ESSs may be located behind or in front of the meter, this analysis assumes that customer-sited systems are located behind the meter in order to simplify the differentiation between system benefits and individual customer benefits. For these specific scenarios, Power Reliability and Outage Mitigation/ Avoided Distribution Investment benefits are mutually exclusive due to the metering configuration. However, real installations may provide opportunities to operate ESSs in a way to blend Power Reliability and Outage Mitigation/ Avoided Distribution Investment benefits. Such opportunities should be evaluated on an installation-specific basis.

- **Utilization:** How frequently the ESS is dispatched to support the application, ranging from low to high
- **Commitment:** How important it is for the ESS to be available at specific times to support the application

Navigant used the last three criteria to assess the stacking compatibility of different applications. Navigant did not evaluate the following applications as part of the stacked use case analysis, as these applications were considered to have low value:

- Voltage Support
- Black Start
- Transmission Congestion
- Distribution Deferral
- Distribution Congestion
- Volt/VAR Control

Furthermore, each application above has moderate-to-high commitment (i.e., Black Start, Transmission Congestion, Distribution Deferral, and Distribution Congestion) and/or utilization (i.e., Voltage Support, Volt/VAR Control), which would detract from capturing greater benefits from other more valuable applications.

Furthermore, multiple related applications were combined together as Energy + Ancillary Services (E+AS), as PGE may perform these in conjunction with one another to maximize value. This aggregated application considers the co-optimized benefits of Energy Arbitrage, Regulation, Load Following, and Spin/Non-spin Reserves, which are all used by PGE to optimize the dispatch of energy storage along with its other generation resources.

Table 2-2 summarizes the compatibility of all applications that were considered for stacking within use cases.

Table 2-2. Application Stacking Compatibility

Application	DCR	TOU	PR	OM/Dx	Tx D	E+AS	Cap
Capacity (**Cap**)	Partially Compatible	Compatible	Highly Compatible	Highly Compatible	Compatible	Compatible	
Energy + Ancillary Services (**E+AS**)	Limited Compatibility	Limited Compatibility	Partially Compatible	Partially Compatible	Compatible		
Transmission Deferral (**Tx D**)	Partially Compatible	Compatible	Highly Compatible	Highly Compatible			
Outage Mitigation/ Avoided Distribution Investments (**OM/Dx**)	Partially Compatible	Partially Compatible	Incompatible				
Power Reliability (**PR**)	Partially Compatible	Partially Compatible					
Time-of-Use Charge Reduction (**TOU**)	Compatible						
Demand Charge Reduction (**DCR**)							

- *Highly Compatible* = The benefits of both applications can be captured at or near their full potential value.
- *Compatible* = The applications can technically be performed with one another, but the full benefits may not be realized, because the target duration for the applications may be different.
- *Partially compatible* = Performing one application directly reduces the benefits of the other.
- *Limited compatibility* = Dispatch decisions would be challenging, because the ESS would be used frequently for both applications, one of which is for customers and the other for PGE.
- *Incompatible* = Applications cannot be performed together, as each application works only at specific grid locations that are mutually exclusive.

Source: Navigant

The following descriptions provide details to explain the compatibility map in Table 2-2:

- **Capacity (Cap)** is generally compatible with most applications. It is highly compatible with OM/Dx and PR since those applications may hold the capacity in reserve and is only infrequently used. For TOU and E+AS, the ESS may be used for other applications at all other times, when not needed for capacity. For Transmission Deferral (Tx D), both applications are infrequently called upon the dispatch and are unlikely to cause conflict, as both are needed during times of peak system demand, and thus the ESS can provide Capacity while also supporting Tx D. However, Cap requires 4 hours of energy storage capacity, while TOU, E+AS, and Tx D may require a shorter duration. For DCR, there can be conflict, as a customer's peak load may not be coincident with system peak load. Thus, one application may need to be prioritized at the expense of the other.

- **Energy + Ancillary Services (E+AS)** has limitations in compatibility, because the ESS is dispatched on a regular basis throughout each day. E+AS is compatible with Cap and Tx D, and the ESS capacity can be held in reserve for these applications during a small number of days of the year, while still extracting most of the E+AS benefits. However, Cap and Tx D may require a longer ESS duration than is required for E+AS. OM/Dx and PR benefits scale with the average state of charge and can therefore be partially derived when performing E+AS. TOU and DCR are customer applications that require the ESS to be frequently dispatched or reserved, thus making it challenging to co-optimize the dispatch of TOU and/or DCR for the customer's benefit in coordination with E+AS for PGE's benefit.
- **Transmission Deferral (Tx D)** has duration, utilization, and commitment constraints similar to those for Cap and therefore has similar compatibility with other applications. It is likely that, similar to Cap, transmission deferral will also require ESSs of about 4 hours in duration, but it may be possible in certain cases for a shorter duration ESS to suffice.
- **Outage Mitigation/ Avoided Distribution Investments (OM/Dx)** is highly compatible with both Cap and Tx D since the energy capacity can be held in reserve for all applications. For DCR, TOU, and E+AS, the OM/Dx benefits scale with the average state of charge of the ESS, as the outages are typically random and do not vary significantly with duration on a $/kWh basis. OM/Dx is incompatible with PR, because OM/Dx represents a system benefit associated with avoided distribution investments, which are socialized across customers, while PR represents an individual customer benefit for customer-sited ESSs that may not be visible to the utility.
- **Power Reliability (PR)** is operationally similar to OM/Dx and therefore has similar compatibility with other applications, and benefits scale with the average state of charge of the ESS. As indicated above, PR is incompatible with OM/Dx, because PR is only applicable for customer-sited ESSs, while OM/Dx is only applicable for distribution-sited ESSs.
- **Time-of-use Charge Reduction (TOU)** is similar to E+AS in that it is dispatched frequently, does not require a long-duration ESS, and can have other applications prioritized above it without significantly reducing benefits. Therefore, its compatibility with other applications is similar. The notable difference is with DCR, where it is easier for a customer to co-optimize TOU and DCR (relative to E+AS and DCR), especially if the customer's peak is during the TOU on-peak period.
- **Demand Charge Reduction (DCR)** is less compatible with stacking in comparison to most applications. For Cap and Tx D, there can be conflict if a customer's peak load is not coincident with system peak load. Thus, one application may need to be prioritized at the expense of the other. For OM/Dx and PR, the benefits scale with the average state of charge, which can be quite high for DCR, as the ESS does not need to be dispatched on most days. Compatibility with E+AS is limited, as it can be challenging to co-optimize the dispatch of DCR for the customer's benefit in coordination with E+AS for PGE's benefit.

Based on the ability to stack these applications, Navigant developed use cases covering the highest-value applications from transmission, distribution, and customer-sited perspectives. Table 2-3 below summarizes the five use cases evaluated in 15 different scenarios (labeled 1a through 5d), while the details and assumptions for each use case are provided in Section 2.3.1 through 2.3.5.

Table 2-3. Use Cases Evaluated

Characteristic	Transmission	Distribution Substation	Distribution Feeder	Medium + Large C&I	Small C&I + Residential
Power	20 MW	10 MW	2 MW	1 MW (aggregated)	1 MW (aggregated)
Duration	2 hr, 4 hr	2 hr, 4 hr	2 hr, 4 hr	2 hr, 4 hr	4 hr
Scenarios	1a. Tx (2h) 1b. Tx (4h)	2a. Dx Sub. (2h) 2b. Dx Sub. (4h)	3a. Dx Feed. (2h) 3b. Dx Feed. (4h) 3c. Dx Feed. (4h, rsvd.)	4a. C&I (2h, PGE) 4b. C&I (4h, PGE) 4c. Med. C&I (4h, DCR) 4d. Lg. C&I (4h, DCR)	5a. Sm. C&I (4h, PGE) 5b. Sm. C&I (4h, TOU) 5c. Resi. (4h, PGE) 5d. Resi. (4h, TOU)
Application			**Scenarios**		
Cap	1a, 1b	2a, 2b	3a, 3b, 3c	4a, 4b, 4c, 4d	5a, 5b, 5c, 5d
E+AS	1a, 1b	2a, 2b	3a, 3b	4a, 4b	5a, 5c
Tx D	1a, 1b	2a, 2b	3a, 3b, 3c	4a, 4b, 4c, 4d	5a, 5b, 5c, 5d
OM/Dx		2a, 2b	3a, 3b, 3c		
PR				4a, 4b, 4c, 4d	5a, 5b, 5c, 5d
TOU					5b, 5d
DCR				4c, 4d	

Source: Navigant

The subsections below provide further details for each use case.

2.3.1 Transmission

The transmission use case assumes an ESS size of 20 MW with a duration of 2 hours (Scenario 1a) and 4 hours (Scenario 1b). In the scenarios evaluated, Transmission Deferral and Capacity each required the ESS to be reserved for 10 days/year. Energy + Ancillary Services took priority for the remainder of the year. Outage Mitigation / Avoided Distribution Investments, Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network. Table 2-4 summarizes the assumptions and scenarios for this use case.

Table 2-4. Transmission Use Case Assumptions

Applications	Value	Business Rules
Power	20 MW	(Assumption)
Duration	1a: 2 hr 1b: 4 hr	(Assumption)
Business Rules	-	Energy + Ancillary Services
Transmission Deferral	$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[14]	Reserved 10 days/yr
Capacity	$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	$60/kW-yr	Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	-	-
Power Reliability	-	-
TOU Charge Reduction	-	-
Demand Charge Reduction	-	-

Source: Navigant

2.3.2 Distribution Substation

The distribution substation use case assumed an ESS size of 10 MW with a duration of 2 hours (Scenario 2a) and 4 hours (Scenario 2b). In the scenarios evaluated, Transmission Deferral and Capacity each required the ESS to be reserved for 10 days/year. Energy + Ancillary Services took priority for the remainder of the year. Outage Mitigation/ Avoided Distribution Investments benefits were small, because the ESS is not targeted at specific circuits with low reliability and a high average value of service. The analysis assumed that Outage Mitigation/ Avoided Distribution Investments benefits scale with the average state of charge, as IPT results indicate that the benefits scale approximately linearly with duration. Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network at a customer site.

For the 4-hour ESS (Scenario 2b), it was assumed that 50% of the energy capacity is used for Energy + Ancillary Services, while 50% of the energy capacity is reserved for Outage Mitigation/ Avoided Distribution Investments, as the ROM analysis indicates that the E+AS benefits do not significantly increase with duration, while the IPT analysis indicates that Outage Mitigation/ Avoided Distribution Investments benefits do scale with duration.

Table 2-5 summarizes the assumptions and scenarios for this use case.

[14] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

Table 2-5. Distribution Substation Use Case Assumptions

Applications	Value	Business Rules
Power	10 MW	(Assumption)
Duration	2a: 2 hr 2b: 4 hr	(Assumption)
Business Rules	-	Energy + Ancillary Services priority
Tx Deferral	$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[15]	Reserved 10 days/yr
Capacity	$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	$60/kW-yr	Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	$2-9-16/kWh	Available capacity used for outages[16]
Power Reliability	-	-
TOU Charge Reduction	-	-
Demand Charge Reduction	-	-

Source: Navigant

2.3.3 Distribution Feeder

The distribution feeder use case assumed an ESS size of 2 MW with a duration of 2 hours (Scenario 3a) and 4 hours (Scenarios 3b and 3c). The ESS was reserved for the benefit of Transmission Deferral and Capacity for 10 days/year for each application. For the 2-hour ESS in Scenario 3a, Energy + Ancillary Services took priority 345 days of the year, and the Outage Mitigation/ Avoided Distribution Investments benefits were assumed to scale with the average state of charge. For the 4-hour system in Scenario 3b, it was assumed that 50% of the energy capacity is used for Energy + Ancillary Services, while 50% of the energy capacity is reserved for Outage Mitigation/ Avoided Distribution Investments. In Scenario 3c, Outage Mitigation/ Avoided Distribution Investments took priority 345 days throughout the year with the ESS at 100% state of charge except for 20 days of the year when needed for Transmission Deferral and Capacity. Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network at a customer site. Table 2-6 summarizes the assumptions and scenarios for this use case.

[15] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[16] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. For a 4-hour ESS, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

Table 2-6. Distribution Feeder Use Case Assumptions

Applications	Value	Business Rules
Power	2 MW	(Assumption)
Duration	3a: 2 hr 3b/3c: 4 hr	(Assumption)
Business Rules	-	3a/3b: Energy + AS priority 3c: Outage Mitigation/ Avoided Distribution Investments priority
Tx Deferral	\$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[17]	Reserved 10 days/yr
Capacity	\$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	\$60/kW-yr	3a/3b: Run when not reserved (345 days/yr) 3c: Not used
Outage Mitigation/ Avoided Distribution Investments	\$3-56-230/kWh	Available capacity used for outages[18]
Power Reliability	-	-
TOU Charge Reduction	-	-
Demand Charge Reduction	-	-

Source: Navigant

2.3.4 Customer (Medium–Large C&I)

The medium–large C&I customer use case assumed an ESS size of 1 MW with a duration of 2 hours (Scenario 4a) and 4 hours (Scenarios 4b, 4c, and 4d). In Scenarios 4c and 4d, Demand Charge Reduction is given priority over all other applications. These ESSs are assumed to be 4 hours, as a 4-hour system will offer greater flexibility than a 2-hour system to perform multiple applications, including Demand Charge Reduction, for a greater number of customers. Only a portion of the aggregated capacity is assumed to be committed as a firm resource for Capacity and Transmission Deferral. The Power Reliability benefits were assumed to scale with the average state of charge. For Scenarios 4a and 4b, the ESS is reserved for 10 days per year for each of Transmission Deferral and Capacity, while Energy + Ancillary Services took priority 345 days of the year, and the Power Reliability benefits were assumed to scale with the average state of charge. For 4-hour ESSs, Scenarios 4c and 4d utilized the entire energy capacity for Demand Charge Reduction, while Scenario 4b used half of the energy capacity for Energy + Ancillary Services and reserved the other half for Power Reliability. TOU Charge Reduction was not considered, as the low margin between peak and off-peak rates for medium–large C&I customers does

[17] The base case assumes the capital cost of transmission is \$125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a \$250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[18] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside for the 4-hour ESS, so the average state of charge is approximately 75%.

not offer as much value as other applications. Outage Mitigation/ Avoided Distribution Investments was not considered, as the application requires the ESS to be located upstream on the distribution network. Table 2-7 summarizes the assumptions and scenarios for this use case.

Table 2-7. Medium / Large C&I Use Case Assumptions

Applications	Value	Business Rules
Power	1 MW, aggregated	(Assumption)
Duration	4a: 2 hr 4b/4c/4d: 4 hr	(Assumption)
Business Rules	-	4c/4d: Demand Charge Reduction priority 4a/4b: Energy + Ancillary Services priority
Tx Deferral	\$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[19]	4c/4d: 20-50-80% firm resource[20] 4a/4b: Reserved 10 days/yr
Capacity	\$120/kW-yr *(4 hr basis)*	4c/4d: 20-50-80% firm resource 4a/4b: Reserved 10 days/yr
Energy + Ancillary Services	\$60/kW-yr	4c/4d: Not used 4a/4b: Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	-	-
Power Reliability	\$1-145-500/kWh	Available capacity used for outages[21]
TOU Charge Reduction	-	-
Demand Charge Reduction	Schedules 83, 85 *(60-80-100% reduction)*	4c/4d: Used as needed (~5%) 4a/4b: Not used

Source: Navigant

2.3.5 Customer (Residential & Small C&I)

The residential (Scenarios 5c and 5d) + small C&I (Scenarios 5a and 5b) use case assumed an aggregated group of ESSs with 1 MW total capacity and a duration of 4 hours. These ESSs are assumed to be 4 hours, as a 4-hour system will offer greater flexibility than a 2-hour system to perform multiple applications, including Demand Charge Reduction, for a greater number of customers. The ESS was reserved for the benefit of Transmission Deferral and Capacity for 10 days/year for each application. In Scenarios 5b and 5d, TOU Charge Reduction took priority 345 days of the year, and the Power Reliability

[19] The base case assumes the capital cost of transmission is \$125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a \$250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[20] On an aggregated basis, it assumed that the aggregated ESSs used for DCR can provide Tx Deferral and Capacity, but that the firm resource that can be committed is only a fraction of the total capacity (low = 20%, base = 50%, high = 80%), as some portion of ESSs may be committed to DCR, particularly during system peak periods.

[21] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

benefits were assumed to scale with the average state of charge. In Scenarios 5a and 5c, the Energy + Ancillary Services took priority 345 days of the year, and the Power Reliability benefits were assumed to scale with the average state of charge. Scenarios 5b and 5d utilized the entire energy capacity for TOU Charge Reduction, while Scenarios 5a and 5c used half of the energy capacity for Energy + Ancillary Services and reserved the other half for Power Reliability. Demand Charge Reduction was not considered, because residential and small C&I customers do not currently have demand charges. Outage Mitigation / Avoided Distribution Investments was not considered, as the application requires the ESS to be located upstream on the distribution network. Table 2-8 summarizes the assumptions and scenarios for this use case.

Table 2-8. Residential / Small C&I Use Case Assumptions

Applications	Value	Business Rules
Power	1 MW, aggregated	(Assumption)
Duration	4 hr	(Assumption)
Scenarios	-	5b/5d: TOU priority 5a/5c: Energy + Ancillary Services priority
Tx Deferral	$125-250/kW *(4 hr, 0-2 yr, 5% capacity ratio)*[22]	Reserved 10 days/yr
Capacity	$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	$60/kW-yr	5b/5d: Not Used 5a/5c: Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	-	-
Power Reliability	Resi = $1/kwh Sm C&I = $1-145-500/kWh	Available capacity used for outages[23]
TOU Charge Reduction	Schedules 7, 32 *(40-70-100% of max reduction)*	5b/5d: Run on weekdays when not reserved 5a/5c: Not used
Demand Charge Reduction	-	-

Source: Navigant

2.4 Energy Storage Technologies

The analytical methodology employed in this analysis has been designed to be technology-agnostic. Key

[22] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[23] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

technology parameters that would affect the net cost-benefit analysis of an actual deployment include the following:

- **Cost:** Cost not only varies significantly between technologies (e.g., Li-ion vs. flow), but also within a given technology, including multiple sub-chemistries, each with variations in pricing between vendors. The cost also depends on the size and duration of the ESS. Further, different technologies and vendors will achieve different levels of cost reduction between now and 2021. This analysis focuses on benefits. PGE will consider representative costs in its energy storage proposals, understanding that actual costs will not be available until PGE receives commercial bids for given ESSs.
- **Lifetime:** For financial evaluation purposes, the ESS life is typically considered equivalent to the warranty period. The actual warranty period not only varies between technologies, but also varies within a specific product, as different warranties can be structured with different associated costs. In this analysis, the lifetime is assumed to be 10 years, which is currently a common warranty period used for different energy storage technologies.
- **Degradation Rate:** The degradation rate impacts the level of achievable benefits over time and depends not only upon the technology, but also upon ESS-specific parameters. For example, degradation depends upon both cycle fade (which depends on the ESS-specific duty cycle) and calendar fade (which is relatively independent of cycling, but may depend on factors such as ambient temperature). Not only is there significant uncertainty in the degradation rate, there are a variety of different approaches to handling degradation, including oversizing the ESS initially to have the energy capacity at end of life (which results in greater capital costs) or regularly replenishing/replacing capacity regularly to maintain a constant capacity (which results in greater operating costs). In this analysis, degradation is assumed to be negligible as a result of regular capacity replenishment, an increasingly common practice by ESS providers.
- **Efficiency:** The efficiency of the ESS does have an impact on both costs and benefits. In this analysis, the round-trip efficiency is assumed to be 90%, which is representative of various technologies including Li-ion batteries, advanced lead-acid batteries, and flywheels.

Thus, because of the significant variability and uncertainty associated with these parameters, PGE prefers to take a technology-agnostic approach to the analysis and evaluate all viable technologies at the time of procurement. While representative parameters will be considered in the final potential evaluation report, PGE will consider actual parameters associated with specific bids at the time of procurement, including other factors not described above (e.g., response time, footprint, etc.).

As indicated above, the baseline analysis in Section 3.1-3.2 considers benefits associated with a generic ESS with a 10-year life, constant capacity, and a 90% round-trip efficiency. In Section 3.3, the analysis evaluates the impact of lifetime, degradation, and efficiency. Furthermore, Table 2-9 provides typical parameters associated with common energy storage technologies.

Table 2-9 Parameters of Common Grid Storage Technologies

Technology	Duration	Size	Efficiency	Lifetime[24]	Location
Mechanical					
PHES[25]	>6 hr	100s MW	75-85%	Decades	Tx
CAES[26]	>6 hr	100s MW	60-70%	Decades	Tx
Flywheel	<1 hr	> 100 kW	80-90%	> 20,000 cycles	Dx - Tx
Electrochemical					
Li-ion	15 min-4 hr	> 5 kW	80-95%	2,000 – 20,000 cycles	BTM – Tx
Flow	> 2 hr	> 5 kW	60-75%	2,000 – 20,000 cycles	BTM – Tx
Advanced Lead-Acid	2-6 hr	> 5 kW	80-90%	1,000 – 4,000 cycles	BTM – Tx
Molten Salt[27]	4-8 hr	> 50 kW	75-85%	2,000 – 5,000 cycles	Dx – Tx

Source: Multiple sources[28]

Other potential energy storage technologies also exist, including the following:

- **Chemical:** Technologies such as hydrogen and syngas are not yet cost-competitive, have low efficiency, and are not as responsive as electrochemical technologies.
- **Thermal:** Two types of thermal storage that are commercially available today include ice storage and electric water heaters. Ice storage provides space conditioning typically to commercial buildings by making ice overnight when electricity prices are low and then using this ice to lower the building's HVAC load during the day, reducing energy and demand charges. Given the moderate climate and low demand charges in PGE's service area, this technology is not commercially viable here at present. Electric water heaters are the primary other version of thermal energy storage. PGE is actively pursuing the use of water heaters both for demand response and for broader grid integration activities.[29] Accordingly, water heaters are not being actively explored by PGE within UM 1751.
- **Other Electronic/Electrochemical:** A variety of different technologies are available that may not have been captured above. These are either not suitable for the target duration (e.g., ultracapacitors) or are not mature enough to warrant special consideration at this point. However, they may be considered at the point of procurement.

[24] Cycle lifetimes reflect equivalent full cycles in the case of duty cycles with partial depth-of-discharge (e.g., frequency regulation).

[25] Pumped hydroelectric energy storage

[26] Compressed air energy storage

[27] Includes sodium sulfur and sodium nickel halide

[28] Values are primarily obtained from the *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA* (2015). The ranges provided reflect typical values, but some exceptions may exist beyond these ranges.

[29] See PGE's 2017 Smart Grid Report, pp. 47-48, 55, 67. http://edocs.puc.state.or.us/efdocs/HAQ/um1657haq16327.pdf.

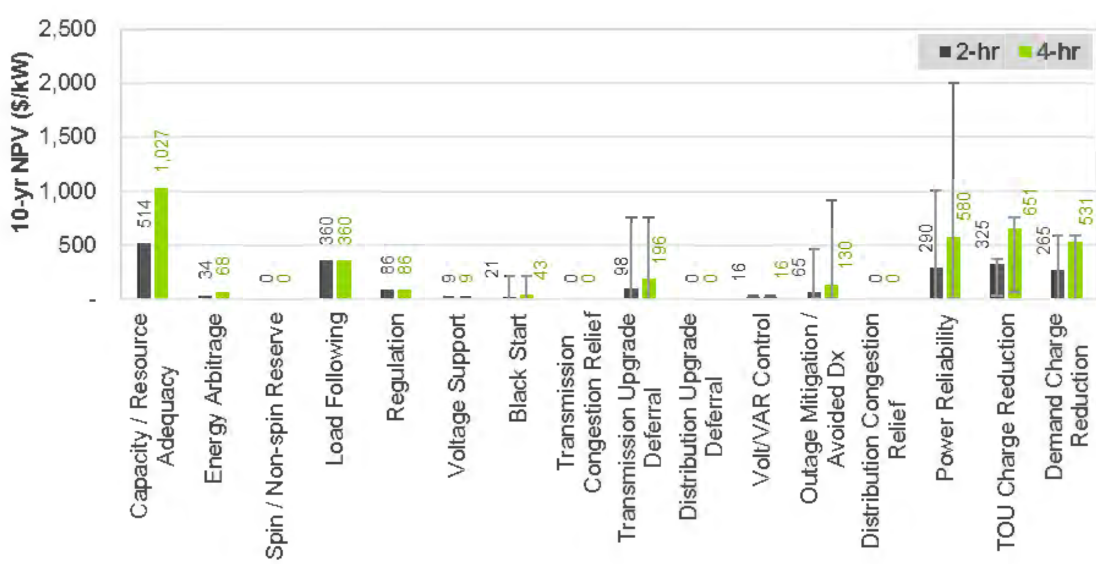
3. RESULTS

This section presents the results of the storage potential evaluation analysis. Section 3.1 evaluates the benefits associated with individual applications. Section 3.2 provides the results associated with the five different use cases, including the results of different scenarios with each use case and low, base, and high conditions associated with each scenario. Within a given use case, Navigant considered different scenarios with different durations (i.e., 2 hours and 4 hours), as well as different business rules for ESS dispatch. Section 3.3 evaluates how these results vary depending upon specific technology parameters.

3.1 Application Benefits

Figure 3-1 illustrates the 10-year NPV of the benefits associated with specific applications. The range and variability of each application is described below in Table 3-1. Note that ranges are provided only for benefits with particularly significant variability and/or uncertainty. Further, it is worth noting that the analysis assumes the benefits only vary over time with inflation. Over time, certain factors (e.g., commodity prices, renewables penetration, changing rate structures, etc.) may have a significant impact on the value of these benefits. Further, the analysis assumes only a modest penetration of energy storage. At larger penetrations, certain benefit streams may be diminished. For example, the value of additional capacity may diminish, or PGE may require longer durations of storage to meet its resource adequacy needs.

Figure 3-1. 10-year Benefits of Each Application[30]



Source: Navigant

[30] Error bars are provided only for applications with significant uncertainty/variability in benefits.

Table 3-1. Benefit Ranges

Application	Base Value[31]	Low Value	High Value	Variation with Duration
Capacity / Resource Adequacy	$120/kW-yr Assume 4-hour ESS required.	(same as base)	(same as base)	4 hours of storage is required, so the benefit is half as much for a 2-hour ESS.
Energy Arbitrage	$4/kWh-yr	(same as base)	(same as base)	Arbitrage benefits roughly scale with energy, so a 4-hour ESS would provide about twice the benefits of a 2-hour ESS. The actual benefits may be slightly less than double, as the margin between discharge and charge decreases with duration.
Spin/ Non-spin Reserve	$0/kW-yr	n/a	n/a	n/a (see Table 2-1)
Load Following	$42/kW-yr	(same as base)	(same as base)	ROM results indicate that the value of an ESS performing Load Following does not vary significantly with duration. Instead, benefits scale with power, so the $/kW value is similar for a 4-hour ESS vs. a 2-hour ESS.
Regulation	$10/kW-yr	(same as base)	(same as base)	Same as Load Following.
Voltage Support	$1/kVAR-yr	$0 PGE does not have a need for the service.	$2/kVAR-yr Assume 2x base value.	Benefits scale with power (kW), so the benefits do not increase with duration.
Black Start	$5/kW-yr Assume 4 hours required.	$0 PGE does not have a need for the service.	$25/kW-yr High end of representative range. Assume 2 hours required.	With 4 hours of storage required, the benefit scales with energy up to 4 hours. For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs.
Transmission Congestion Relief	$0	n/a	n/a	n/a (see Table 2-1)
Transmission Upgrade Deferral	$125/kW Tx capacity Assume 1 year of deferral with 4 hours required.	$0 Assume grid location limits deferral value.	$250/kW Tx capacity Assume 2 years of deferral with 2 hours required.	With 4 hours of storage required, the benefit scales with energy up to 4 hours. For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs.
Distribution Upgrade Deferral	$0	n/a	n/a	n/a (see Table 2-1)

[31] Values reflect 2016 dollar values. Units vary depending upon how each value scales. Values may scale with energy (kWh), real power (kW), or reactive power (kVAR). Further, some values represent annual benefits (e.g., $/kW-year), while others represent 10-year lifetime benefits (e.g., $/kW).

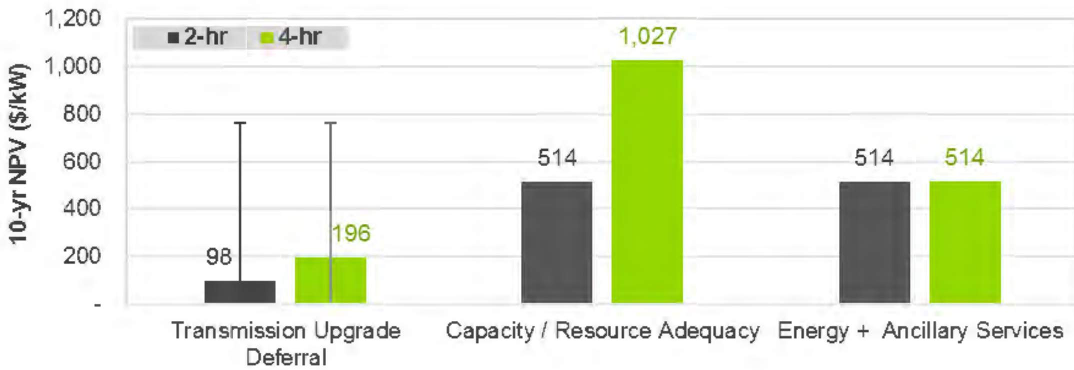
Application	Base Value[31]	Low Value	High Value	Variation with Duration
Volt/VAR Control	$16/kVAR	$8/kVAR Assume cost is half of representative recent investment.	$32/kVAR Assume cost is twice of representative recent investment.	Benefits scale with power (kW), so the benefits do not increase with duration.
Outage Mitigation/ Avoided Distribution Investments	$32/kWh Average of averages at substation and feeder levels	$2/kWh Lowest value at substation level	$225/kWh Highest value at feeder level	The IPT analysis demonstrates that benefits scale approximately linearly with duration, so the value of a 4-hour ESS is about twice the value of a 2-hour ESS.
Distribution Congestion Relief	$0	n/a	n/a	n/a (see Table 2-1)
Power Reliability	$140/kWh Average value at customer level	$1/kWh Lowest value at customer level	$490/kWh Highest value at customer level	The IPT analysis demonstrates that benefits scale approximately linearly with duration, so the value of a 4-hour ESS is about twice the value of a 2-hour ESS.
TOU Charge Reduction	$19/kWh-yr Small C&I	$2/kWh-yr Medium and Large C&I	$22/kWh-yr Residential	Benefits scale linearly with duration up to 5 hours (duration of on-peak period), so the value of a 4-hour ESS is about twice the value of a 2-hour ESS.
Demand Charge Reduction	$62/kW-yr Large C&I. Assume 4 hours required.	$0/kW-yr Residential and Small C&I	$69/kW-yr Medium C&I. Assume 2 hours required.	With 4 hours of storage required, the benefit scales with energy up to 4 hours. For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs.

Source: Navigant

3.1.1 Transmission-Sited Energy Storage Systems

Based on the analysis above, Navigant selected Transmission Upgrade Deferral, Capacity, and Energy + Ancillary Services for inclusion in the use cases with transmission-sited ESSs. Navigant excluded Transmission Congestion Relief, Black Start, and Voltage Support due to their relatively low value and moderate-to-high level of commitment, which impedes the more valuable collection of applications within Energy + Ancillary Services. Figure 3-2 summarizes the benefits of each individual application. Note that these values reflect independent applications and do not consider reductions in total value due to stacking.

Figure 3-2. Benefits of Selected Applications for Transmission-Sited ESSs

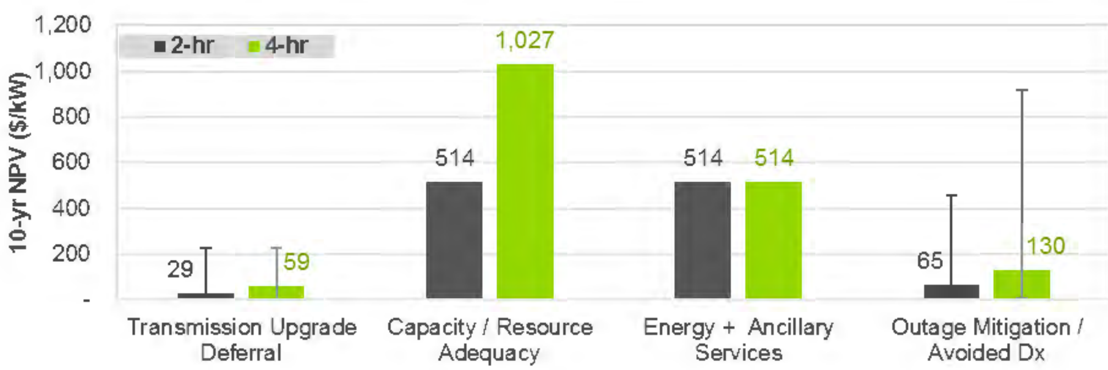


Source: Navigant

3.1.2 Distribution-Sited Energy Storage Systems

The use cases for distribution-level ESSs consider all selected transmission applications, as well as Outage Mitigation/ Avoided Distribution Investments. Distribution Congestion Relief, Distribution Upgrade Deferral, and Volt/VAR were excluded due to their low value and moderate-to-high level of commitment, which impede with the more valuable collection of applications within Energy + Ancillary Services. Figure 3-3 summarizes the benefits of each individual application. Note that these values are for independent applications and do not consider reductions in total value as a result of stacking. These do, however, consider differences in potential benefits at the distribution level. As described in Section 3.2.2, Transmission Upgrade Deferral benefits are lower than at the transmission level, and Outage Mitigation/ Avoided Distribution Investments benefits are lower than the Power Reliability benefits at the customer level.

Figure 3-3. Benefits of Selected Applications for Distribution-Sited ESSs

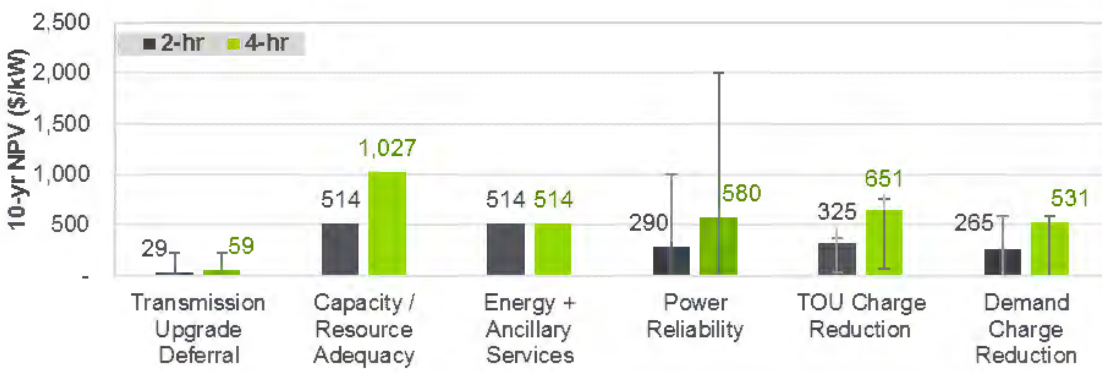


Source: Navigant

3.1.3 Customer-Sited Energy Storage Systems

The use cases for customer-level ESSs consider all selected applications for the transmission- level and distribution-level use cases, as well as TOU Charge Reduction and Demand Charge Reduction (DCR). Figure 3-4 summarizes the benefits of each individual application. Note that these values are for independent applications and do not consider reductions in total value as a result of stacking. These do, however, consider differences in potential benefits at the customer level. As described in Section 2.3, Transmission Upgrade Deferral benefits are lower than at the transmission level, and Power Reliability benefits are higher than the Outage Mitigation/ Avoided Distribution Investments at the distribution level.

Figure 3-4. Benefits of Selected Applications for Customer-Sited ESSs

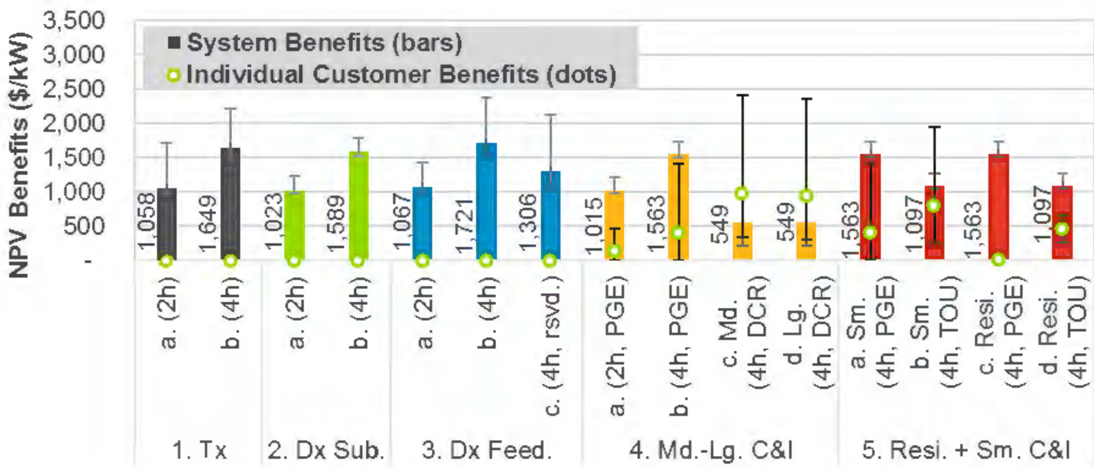


Source: Navigant

3.2 Optimized Use Cases

Figure 3-5 summarizes the range of benefits obtained for each of the use cases.[32] The results delineate between system benefits (all benefits except TOU and DCR) and individual customer benefits (bill savings from TOU and DCR). The details for each use case are discussed in greater detail in Section 3.2.1 through Section 3.2.5. The assumptions and inputs for each use case are described in Section 2.3. The error bars show the range of results between the low and high conditions. The inputs for the base, low, and high conditions are described for each use case in Section 2.3.1 through 2.3.5.

Figure 3-5. Summary of Results for all Use Cases



Source: Navigant

[32] All NPV benefits were calculated in 2020 USD based on the weighted average cost of capital (6.204%), then converted to 2017 USD based upon assumed inflation (2%).

Figure 3-6 compares the system benefits of 4-hour vs. 2-hour ESSs at different grid locations. The ratio between system benefits of 4-hour ESSs and the benefits of 2-hour ESSs generally increases going from the transmission level down to the feeder level. There is then a drop-off in in the benefit ratio at the customer level, in part because the Power Reliability benefits are individual customer benefits, whereas Outage Mitigation/ Avoided Distribution Investments benefits are system benefits. For all examples in Figure 3-6, the 4-hour ESS provides greater benefits than a 2-hour ESS at ratio of approximately 1.3 or higher. The ratio is typically about 1.5 and is nearly 1.7 in certain cases. Whether a 2-hour or 4-hour ESS is preferable depends upon the ratio of costs between them.

Figure 3-6. System Benefits of 4-hour vs. 2-hour ESSs

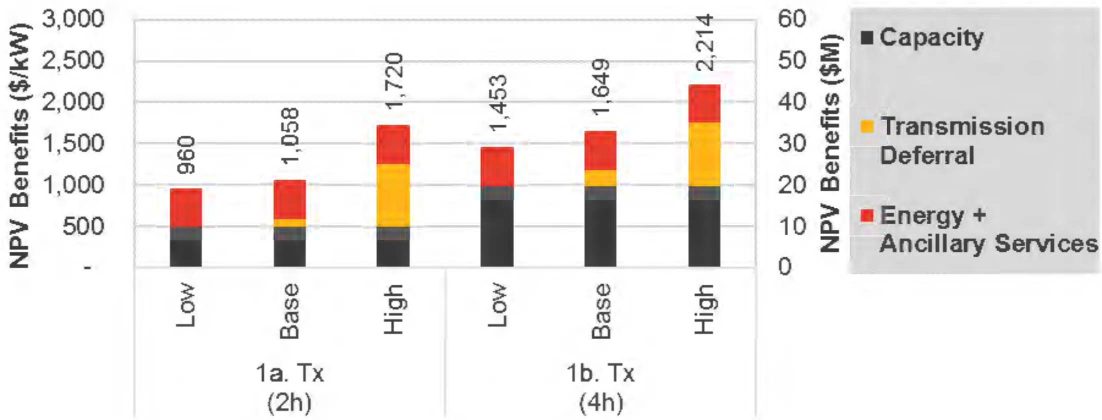
Source: Navigant

3.2.1 Case 1: 20 MW ESS on Transmission Line

Figure 3-7 illustrates the system benefits under each of the transmission-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Two scenarios were evaluated, including one for a 2-hour ESS (1a) and one for a 4-hour ESS (1b). In each case, the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days. The inputs and assumptions for transmission-level ESSs are described in Table 2-3 and Section 2.3.1.

Figure 3-7. System Benefits of 20 MW Transmission-sited ESSs



Source: Navigant

The benefits increase going from a 2-hour to a 4-hour ESS primarily due to additional Capacity benefits, as 4 hours of storage are required, so only half of the benefit is realized for a 2-hour ESS. The Transmission Deferral benefits are also higher for the 4-hour ESS in the base case, as it assumed that 4 hours of storage are required. However, it is assumed that only a 2-hour ESS is required in the high case.

The key source of variability between the low, base, and high conditions is the Transmission Deferral benefit. The Capacity and E+AS benefits were assumed to be the same for all, as the confidence in the level of these benefits obtained from the ROM analysis is relatively high. However, for Transmission Deferral, the following factors may vary:

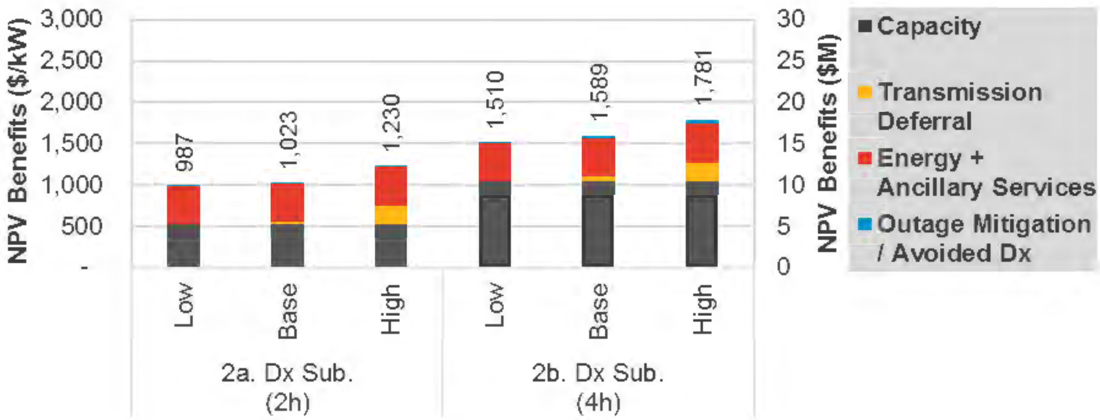
- Required duration (low/base = 4 hours, high = 2 hours)
- Cost of transmission equipment, based on the type of investment (low/base = $125/kW, high = $250/kW)
- Deferral period (low/base = 1 year, high = 2 years)
- Capacity of transmission deferred (low = 0 kW, base/high = 20 kW transmission per kW storage)

3.2.2 Case 2: 10 MW ESS at Distribution Substation

Figure 3-8 illustrates the system benefits under each of the substation-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Two scenarios were evaluated, including one for a 2-hour ESS (2a) and one for a 4-hour ESS (2b). In each case, the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days. The inputs and assumptions for substation-level ESSs are described in Table 2-3 and Section 2.3.2.

Figure 3-8. System Benefits of 10 MW Substation-sited ESSs



Source: Navigant

Relative to transmission-level ESSs, the key difference is the amount of Transmission Deferral benefits. PGE analysis indicates that load reductions at the distribution level yield only ~30% impact along any transmission route (i.e., 10 MW distribution load reduction = 3 MW load reduction along a specific transmission route), so the distribution-level benefits are assumed to be 30% of the transmission-level benefits.

The differences in other benefits are relatively small. The Capacity and E+AS benefits are similar, except the Capacity benefits at the distribution level are slightly higher (~5%) due to reduced T&D losses during peak periods. The Outage Mitigation/ Avoided Distribution Investments benefits are minimal, as substation-level storage is only able to mitigate transmission-level outages, while most outages are driven by events at the distribution level.

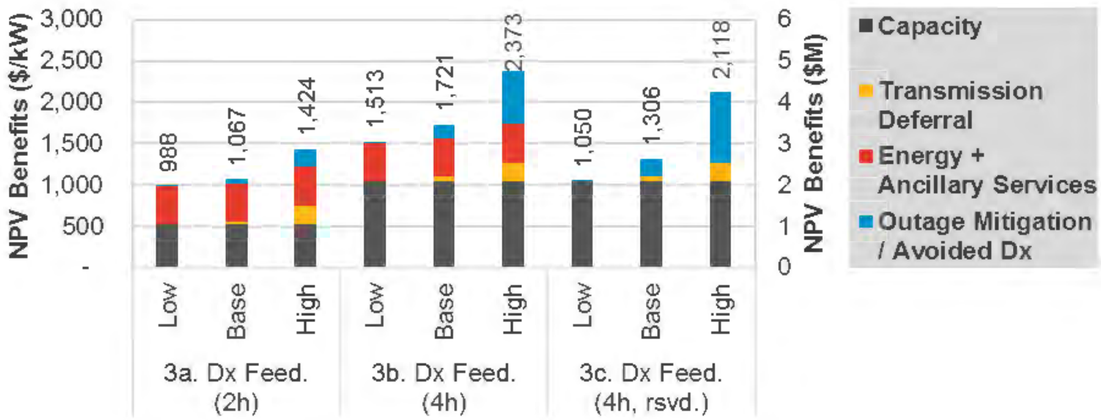
The sources of variability between the low, base, and high conditions are the same as for the transmission-sited ESS for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. For the Outage Mitigation/ Avoided Distribution Investments benefits, the benefits vary by substation depending upon the frequency of transmission outages at the substation, and the average value of service for impacted customers.

3.2.3 Case 3: 2 MW ESS on Distribution Feeder

Figure 3-9 illustrates the system benefits under each of the feeder-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Three scenarios were evaluated. In the first two scenarios – one with a 2-hour ESS (3a) and one with a 4-hour ESS (3b) – the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days, and the Outage Mitigation/ Avoided Distribution Investments application is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the third scenario (3c), the ESS is reserved for Outage Mitigation/ Avoided Distribution Investments during all times when not needed for Capacity or Transmission Deferral (345 days/year). The inputs and assumptions for feeder-level ESSs are described in Table 2-3 and Section 2.3.3.

Figure 3-9. System Benefits of 2 MW Feeder-sited ESSs



Source: Navigant

Relative to substation-level ESSs, the key difference is the amount of Outage Mitigation/ Avoided Distribution Investments benefits. These benefits are higher than at the substation level, as feeder-level ESSs can help to mitigate distribution-level outages in additional to transmission outages, particularly on long feeders without robust tie lines. There is, however, significant variability in these benefits, as they depend upon the configuration of the feeder, the frequency of outages on the feeder, and the average value of service for impacted customers. Further, the benefits for 4-hour ESSs are greater, because only a 2-hour ESS is needed for E+AS, leaving 50% of the total energy capacity available for Outage Mitigation/ Avoided Distribution Investments except when occasionally needed for Capacity or Transmission Deferral.

For 4-hour ESSs, another scenario (3c) was analyzed that looked at the relative benefits for an ESS that is not used for E+AS and instead holds all of the energy storage capacity in reserve at all times, except when occasionally needed for Capacity or Transmission Deferral. In this case, the average available energy capacity increases from ~75% to nearly 100%. Thus, the Outage Mitigation/ Avoided Distribution Investments benefits increase by about one third in this case. However, the loss in E+AS benefits outweighs this impact, resulting in lower total benefits even in the high condition. Thus, it generally makes sense to utilize the ESS for E+AS rather than holding the full capacity in reserve for Outage Mitigation/ Avoided Distribution Investments. This finding may vary for certain feeders.

The sources of variability between the low, base, and high conditions are similar to the previous use cases for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. For the Outage Mitigation/ Avoided Distribution Investments benefits, the benefits vary by feeder depending upon the configuration of the feeder, the frequency of outages on the feeder, and the average value of service for impacted customers.

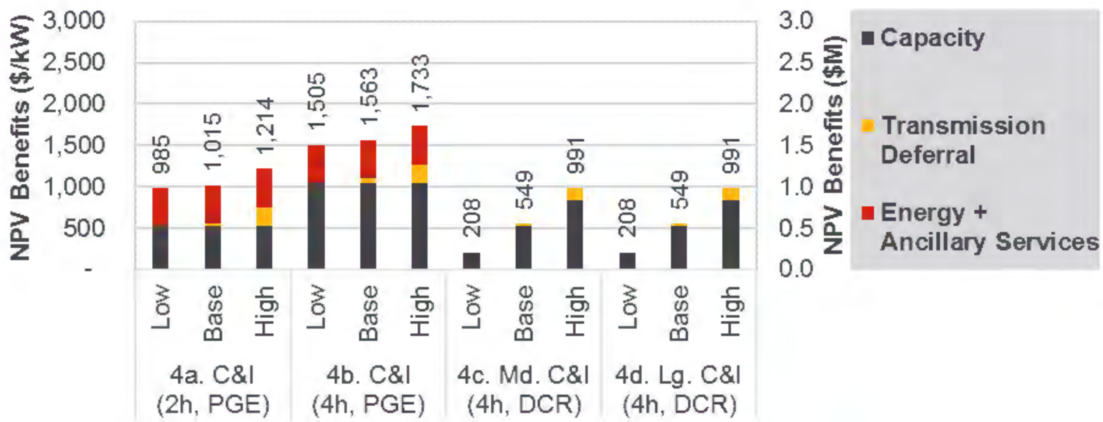
3.2.4 Case 4: 1 MW Aggregated Medium–Large C&I Customers

Figure 3-10 illustrates the system benefits under each of the customer-level scenarios analyzed for medium-to-large C&I customers,[33] while Figure 3-11 illustrates the benefits to the customer where the ESS is sited. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits.

[33] Customers on rate schedules 83 (31 – 200 kW) or 85 (201 – 4,000 kW).

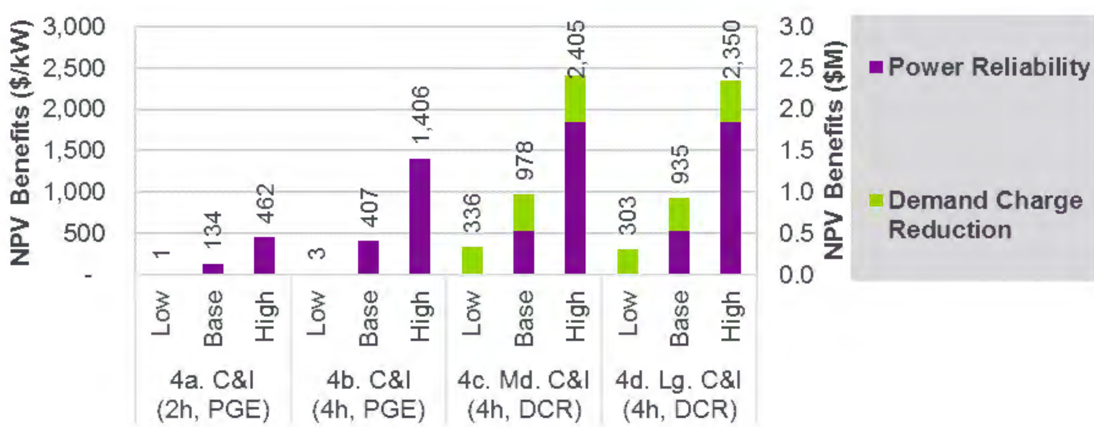
Four scenarios were evaluated. In the first two scenarios – one with a 2-hour ESS (4a) and one with a 4-hour ESS (4b) – the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the last two scenarios – one for a medium C&I customer (4c) and one for a large C&I customer (4d) – the ESS is used primarily for Demand Charge Reduction. A portion of the aggregated capacity is available when needed for Capacity and Transmission Deferral, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. The inputs and assumptions for these ESSs are described in Table 2-3 and Section 2.3.4.

Figure 3-10. System Benefits of 1 MW Aggregated Customer-sited ESSs (Medium-Large C&I)



Source: Navigant

Figure 3-11. Individual Customer Benefits of 1 MW Aggregated Customer-sited ESSs (Medium-Large C&I)



Source: Navigant

The first two scenarios (4a, 4b) evaluate 2-hour and 4-hur ESSs are operationally similar to feeder-level ESSs, as they are operated by PGE for E+AS. The key difference relative to feeder-level ESSs is the amount of Power Reliability benefits relative to Outage Mitigation/ Avoid Distribution Investments benefits and the fact that Power Reliability provides individual customer benefits rather than system benefits.

Placing the ESS at specific customer sites can target specific locations with high value of service.[34] As discussed in Section 2.2.3.2, Power Reliability benefits for individual customers are likely to vary significantly from customer to customer. Because the benefit accrues uniquely to one customer, the benefit does not stack on the system benefits and instead is an individual customer benefit.

The last two scenarios (4c, 4d) evaluate 4-hour ESSs at medium and large C&I customer sites used for Demand Charge Reduction (DCR) rather than for E+AS. The key differences are:

- Lower Capacity and Transmission Deferral benefits due to lower guaranteed available capacity (low = 20%, base = 50%, high = 80%)
- No E+AS benefits
- Higher PR benefits (i.e., higher average state of charge for DCR vs. E+AS)
- DCR benefits included

The sources of variability between the low, base, and high conditions are the similar to the previous use cases for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. In addition, the Capacity and Transmission Deferral benefits scale depending upon the assumed level of guaranteed capacity. For the Power Reliability benefits, the benefits vary by customer depending upon the configuration of the associated feeder, the frequency of outages for the customer, and the value of service for the customer. For DCR, the average monthly demand reduction may vary depending upon the customer's load profile (assumed reduction relative to ES power rating: low = 60%, base = 80%, high = 100%) and the demand charge (which was the only assumed difference between medium and large C&I customers).

Overall, the system benefits are significantly lower for the DCR ESSs. The magnitude of the individual customer benefits from DCR is similar to the system benefits from E+AS when operated by PGE. However, the DCR benefits also result in lower revenue for PGE, which may increase costs to other customers and is not accounted for in the system benefits. The Power Reliability benefits can be quite high in certain cases, but these benefits accrue to a specific customer.

3.2.5 Case 5: 1 MW Aggregated Small C&I + Residential Customers

Figure 3-12 illustrates the system benefits under each of the customer-level scenarios analyzed for small C&I and residential customers,[35] while Figure 3-13 illustrates the benefits to the customer where the ESS is sited. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits.

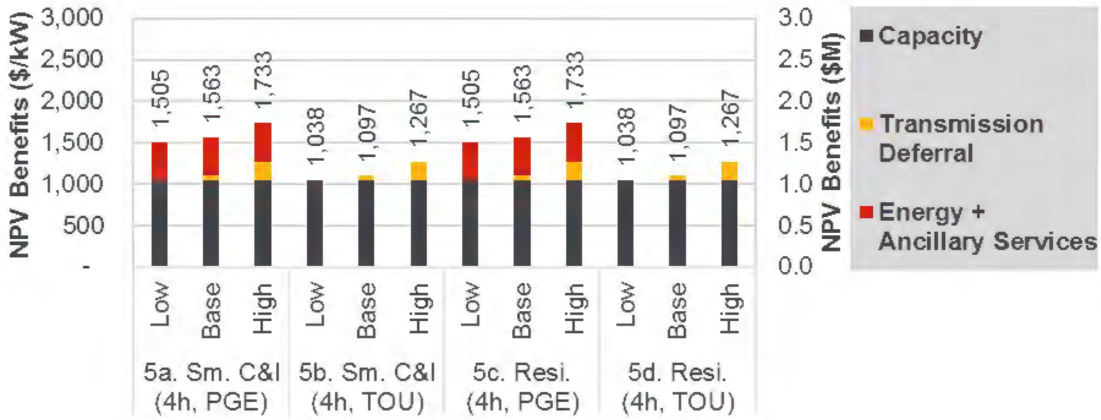
Four scenarios were evaluated. In two scenarios – one for a small C&I customer (5a) and one for a residential customer (5c) – the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the last two scenarios – one for a small C&I customer (5b) and one for a residential customer (5d) – the ESS is used for TOU Charge Reduction instead of Energy + Ancillary Services when not needed for Capacity and Transmission Deferral, and Power Reliability is available with a varying energy capacity depending upon

[34] Note that the range of Power Reliability values shown here is from a selected sample of customers that may have a higher average benefit relative to the system-wide average for all PGE customers.

[35] Customers on rate schedules 7 (residential) or 32 (C&I, <30 kW).

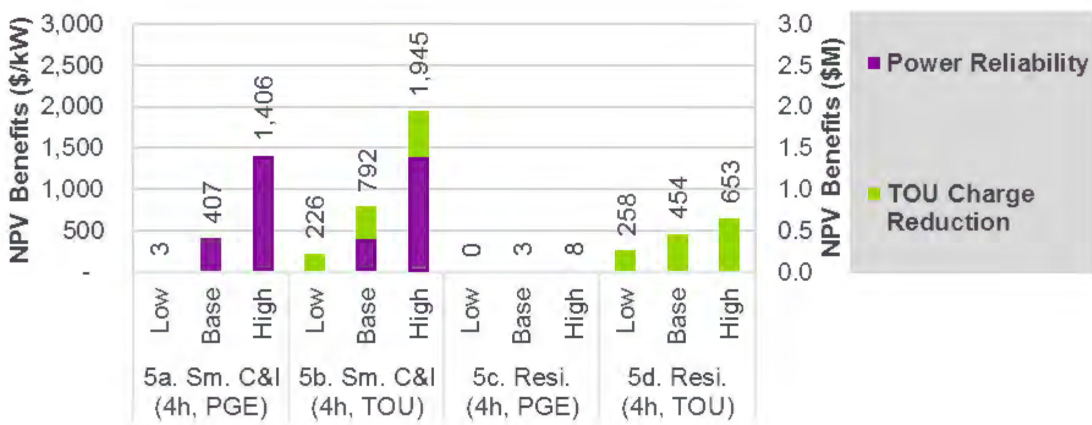
the state of charge when an outage occurs. The inputs and assumptions for these ESSs are described in Table 2-3 and Section 2.3.5.

Figure 3-12. System Benefits of 1 MW Aggregated Customer-sited ESSs (Small C&I + Residential)



Source: Navigant

Figure 3-13. Individual Customer Benefits of 1 MW Aggregated Customer-sited ESSs (Small C&I + Residential)



Source: Navigant

The “PGE” scenarios evaluate 4-hour ESSs that are operationally similar to the ESSs operated by PGE at medium and large C&I customer sites. The results for small C&I customers are identical to those for medium and large C&I customers, as there is no assumed difference in Power Reliability benefits. However, the Power Reliability benefits are assumed to be significantly lower for residential customers due to a lower value of service.

The TOU scenarios in Figure 3-12 evaluate 4-hour ESSs used for TOU Charge Reduction, rather than E+AS. Relative to the ESSs utilized for E+AS, these ESSs have:

- The same Capacity and Transmission Deferral benefits
- No E+AS benefits

- Similar PR benefits (i.e., similar average state of charge for TOU vs. E+AS)[36]
- TOU benefits included

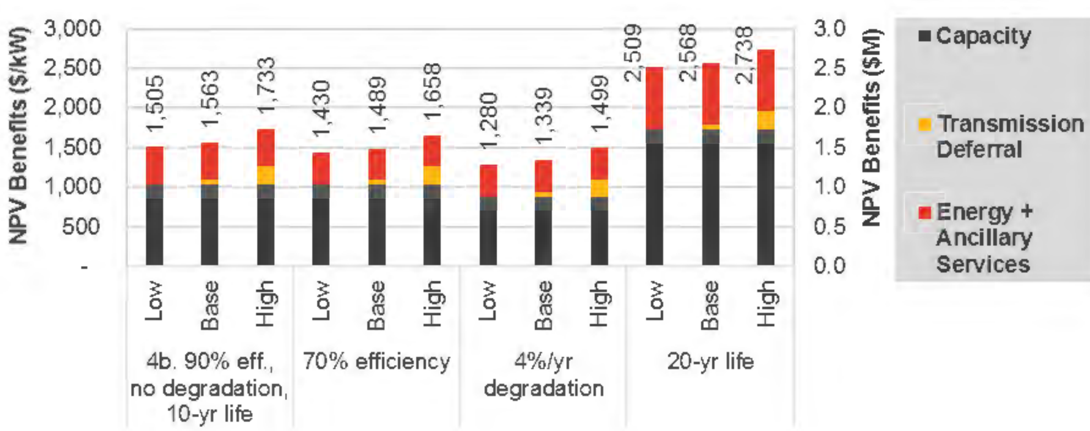
The sources of variability between the low, base, and high conditions are the similar to the prior use case for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. As with medium and large C&I customers, the Power Reliability benefits for small C&I customers vary by customer depending upon the configuration of the associated feeder, the frequency of outages for the customer, and the value of service for the customer. For residential customers, the value of service is assumed to be low under all conditions. The average monthly TOU benefits may vary depending upon the customer's load profile, as the ESS capacity may exceed the customer's load during peak hours (assumed TOU reduction relative to max potential reduction: low = 40%, base = 70%, high = 100%) and the TOU rate schedule.

Thus, the system benefits are lower due to the lack of E+AS benefits. The magnitude of the individual customer benefits from TOU is similar to the system benefits from E+AS when operated by PGE. However, the TOU benefits also result in lower revenue for PGE, which may increase costs to other customers and is not accounted for in the system benefits. The PR benefits can be quite high in certain cases, but these benefits accrue to a specific customer.

3.3 Technology Comparison

To evaluate the impact of technology on the NPV of lifetime system benefits, key technology parameters (efficiency, degradation, and lifetime) discussed in Section 2.4 were varied for the 4-hour PGE-controlled ESS located at a C&I customer site (4b). This specific scenario was selected to illustrate the impact of these parameters on a variety of benefit streams. The conclusions from this analysis illustrate how benefits would scale under other use cases and scenarios. Figure 3-14 and Figure 3-15 summarize these results for system benefits and individual customer benefits, respectively.

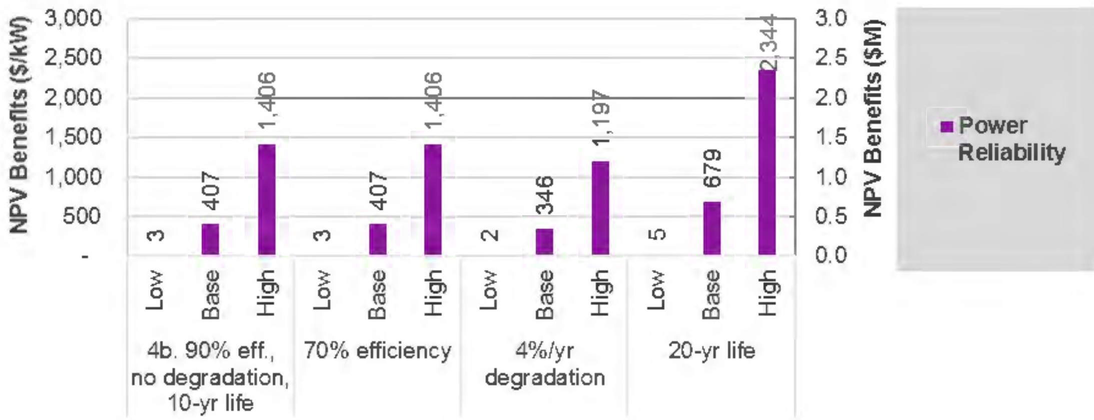
Figure 3-14. Impact of Technology Parameters on System Benefits



Source: Navigant

[36] The average state of charge for TOU is higher, but it uses the entire ESS, while the average state of charge for E+AS is lower, but it only uses half of a 4-hour ESS.

Figure 3-15. Impact of Technology Parameters on Individual Customer Benefits



Source: Navigant

This analysis demonstrates that the impact of efficiency for this use case is relatively small, because most of the benefits (Capacity, Transmission Deferral, and Outage Mitigation/ Avoided Dx) stem from occasional use of the ESS and do not require frequent cycling. The only benefit stream significantly affected by efficiency is E+AS. The E+AS benefits for the 70% efficiency scenario were ~85% of their value for the reference scenario with 90% efficiency. Total system benefits were >95% relative to the reference scenario.

The impact of degradation is more notable, because it has a more significant impact on most benefit streams. The impact on Transmission Deferral benefits is minimal, because those benefits accrue in the first 1-2 years. However, the Capacity, E+AS, and Power Reliability streams are all ~15% lower for the 4%/year degradation scenario relative to the reference scenario with no degradation, as it is assumed the capacity available for each application decreases with the available energy capacity.[37] Because the Transmission Deferral benefits are relatively small, overall systems benefits were also ~15% lower than the reference scenario.

The impact of ESS life is more profound. An ESS with a 20-year life produces nearly 67% more benefit than the reference ESS with a 10-year life. As is the case for degradation, the Capacity, E+AS, and Power Reliability streams are all similarly impacted, while the Transmission Deferral benefits remain about the same. Note that both the 10-year and 20-year cases assume no degradation, which is the result of regular capacity replenishment. If degradation was significant and capacity was not replenished, the impact of extending the life of the ESS to 20 years would be somewhat diminished.[38]

[37] Note that while 4%/year degradation is relatively high, it provides a representative case of significant degradation, and it may be somewhat representative for this use case, in which the ESS is cycled nearly twice per day for Energy + Ancillary Services. Additionally, while the ESS degrades below 70% of initial capacity by the end of the 10-year period (which is below the common 80% threshold), it is not assumed that any replacement or replenishment occurs.

[38] Here, ESS life is assumed to be independent of degradation. Typically, these two parameters are related to one another, often based on the time to degrade to 80% of original energy capacity. However, the ESS life is typically equal to the warranty period for financial purposes, and warranties can have varying periods for the same technology, depending upon how they are structured.

APPENDIX A. OPUC ANALYSIS REQUIREMENTS

As outlined in UM 1751, Table A-1 provides the storage potential evaluation issues that should be addressed, examined and resolved at the staff workshops in the first half of 2017.

Table A-1. Recommended Evaluation Framework

Requirement	Analysis Approach
Establish a consistent list of use cases or applications to be considered in the Evaluation	Evaluate use cases identified in Appendix A of UM 1751 Staff Recommendation document and included in report Table 2-3.
Establish a consistent list of definitions of key terms	As defined in the US Department of Energy Glossary of Energy Storage Terms and *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*.
Timeframe for analyses	10 years for initial analysis. For the proposal, due on January 1, 2018, the analysis timeframe should be equal to the lifetime and life-cycle cost of the proposed ESS.
Potential valuation methodology or methodologies the electric companies may use for estimating storage potential in each use case or application	Incorporate the agreed-upon list of factors provided in Appendix A of UM 1751 Staff Recommendation document and included in report Table 2-1.
Criteria for identifying the main opportunities for investment in storage	Cost-effectiveness, diversity, location, and utility learning.
Approach for identifying system locations with the greatest storage potential	Considering five generic locations for draft evaluation: transmission, distribution substation, distribution feeder, residential/small C&I customers, and medium/large C&I customers. PGE will look at specific locations for the final potential evaluation report.
Level of detail required in the evaluation results and required supporting data.	Detailed in Table A-2.

Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

One of the recommended steps in the evaluation framework is to develop a potential valuation methodology to estimate storage potential in each use case or application. Table A-2 provides the key elements as outlined in the staff public meeting on March 21, for consideration in the potential evaluation. These key elements provided guidance for the potential evaluation detailed in this report.

Table A-2. Key Elements for Potential Evaluation

Requirement	Analysis Approach
Electric companies should analyze each use case listed in Appendix A for each evaluated storage site.	The analysis considers use cases consisting of a set of applications performed by an ESS at a grid location (transmission, substation, feeder, or BTM).
Final Storage Potential Evaluations Should include detailed cost estimates for each proposed storage system.	Draft evaluation focuses on benefits, rather than costs.
When storage services can be defined based upon market data, a market valuation should be used for such identified services.	Where available, market pricing was used as a basis. Otherwise, avoided costs were used.

Requirement	Analysis Approach
Final evaluations submitted by January 1, 2018 should provide detailed descriptions of the proposed sites.	Out of scope for the draft evaluation.
"Resiliency" should be defined in the form of a use case or as a unique, quantifiable benefit if it is included in the Final Storage Potential Evaluation.	Value of resiliency/reliability is incorporated within the IPT analysis of Outage Mitigation and Power Reliability benefits.
The components of each model, including the attributes in Staff Recommendation No. 6, should be identified and drafted in both the draft and final evaluations.	These applications are addressed in Table 1-1.
A single base year may be used for modeling purposes.	Simulation of operational value was undertaken for a 2021 test year due to data availability through the 2016 IRP and the timing of PGE's incremental capacity need.
Staff must be able to validate the assumptions and methods used to evaluate the cost-effectiveness of each proposed ESS in the final proposals.	The methodology, including models, assumptions, and data sources, is described herein.

Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

Navigant used the modeling attributes outlined in the staff public meeting on March 21, to help guide energy storage potential modeling decisions. Energy storage has several unique characteristics, and staff views it as essential that any models used in the evaluations have the attributes listed in Table A-3. Staff believes that the June 1, 2017, draft evaluations do not need to include the first three items but the attributes included need to be documented clearly. Nonetheless, these items are incorporated into the analysis described herein.

Table A-3. Modeling Attributes

Attribute	Analysis Approach
Capacity to evaluate sub-hourly benefits	Sub-hourly analysis is used in ROM (15-min intervals with reserves to manage fluctuations down to one minute).
Ability to evaluate location-specific benefits based on utility-specific values	ESSs sited at general transmission, substation, feeder, and customer locations are considered herein. Locational benefits from the IPT model are based on PGE-specific parameters. Specific sites are to be considered by PGE in the final evaluation.
Enables co-optimization between services	ROM analysis co-optimizes energy and ancillary services. The use cases run in NVEST prioritize different applications and the utilization of the ESS for those applications based upon their value and compatibility.
Capacity to evaluate bulk energy, ancillary service, distribution-level, and transmission-level benefits	Benefits are assessed for each application in Section 3.1.
Ability to build ES conditions (e.g., power/energy capacity, charge/discharge rates, charging/discharging efficiencies, efficiency losses) into the optimization	The analysis in Section 2.3 considers the impact of ESS sizing, while the analysis in Section 2.4 considers the impact of efficiency, degradation, and lifetime. Optimized dispatch in ROM takes into account the listed ES conditions in every time step.

Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

APPENDIX B. MODELING DETAILS

The following sections provide additional detail regarding the modeling tools and approach used, beyond the discussion in Section 2.2.

B.1 Navigant Valuation of Energy Storage Tool (NVEST)

Section 2.2.1 describes the NVEST model at a high level. As mentioned above, a detailed description of the basic methodology is publicly available online.[39] Further, many of the assumptions, inputs, and data sources specifically associated with the analysis in this report are described elsewhere within the document:

- Section 2.1 describes the analytical approach and data sources used for each application;
- Section 2.2 describes the sources for the inputs and assumptions that were used;
- Section 2.3 describes the assumptions associated with each use case; and
- Section 2.4 describes the assumptions associated with the energy storage technology and performance.

The list below describes other important assumptions used to determine the value of each use case.

- The net present value (NPV) of each use case reflects the net operating benefit of the ESS. It includes both the benefits accrued from operating the ESS for specific applications, as well as the variable operating costs associated with operating the ESS (e.g., charging costs). It does not include costs associated with ESS ownership (i.e., installed capital costs, as well as fixed operating and maintenance costs).
- Values associated with the energy capacity (kWh) and power capacity (kW) of the ESS (e.g., annual kW available for Energy + Ancillary Services) are reduced by the assumed degradation rate (e.g., 2%/year). Degradation is assumed to be exponential (i.e., Capacity in year 10 = $(1 – 2\%)^9$ = 83% of original capacity).
- Values associated with system benefits (e.g., $/kW-year for Energy + Ancillary Services) are assumed to escalate at inflation rate of 2% per year. Input values are escalated from their base year (typically 2016) to their value in the initial year (2021), as well escalated during each year of the deployment (typically through 2030).
- The NPV is calculated assuming a discount rate/ weighted average cost of capital of 6.204%. The ESS is assumed to be deployed in 2021, and the NPV is calculated in 2020 USD based upon the assumption that an investment is made in 2020 before the ESS goes live in 2021. This NPV is then converted to 2017 USD by adjusting for inflation (2%).

B.2 Resource Optimization Model (ROM)

PGE engaged in detailed modeling of ESSs within the 2016 IRP using ROM. ROM is a multi-stage production simulation model of PGE's resource portfolio. ROM was originally designed to quantify operational challenges and costs associated with renewables integration. In addition to energy storage

[39] DOE Energy Storage Computational Tool Overview. US Department of Energy. August 2012. https://www.smartgrid.gov/document/doe_energy_storage_computational_tool_overview.html.

evaluation, ROM is used to calculate PGE's Variable Energy Integration Costs as well as the Day-Ahead Forecast Error costs associated with wind generation in PGE's calculation of Net Variable Power Costs. Recent ROM development work has been discussed in past and ongoing IRP dockets, including LC 56 and LC 66. Key model development decisions and subsequent enhancements were also reviewed by an external Technical Review Committee. Because of this history, ROM already incorporated the key features required for quantifying the operational value of energy storage resources: optimal unit commitment and dispatch of the PGE resource fleet over multiple time horizons, impacts of forecast errors (e.g., day-ahead to real-time), ancillary service requirements, and sub-hourly dispatch. More information about ROM and PGE's preliminary energy storage evaluation can be found in Chapter 8 of the 2016 IRP.[40]

Positive discussions with stakeholders regarding PGE's approach to modeling energy storage in the 2016 IRP encouraged the Company to continue to explore energy storage evaluation through production simulation modeling exercises. PGE also received positive feedback on its methodology from utilities and industry organizations across the country. PGE's methodology was highlighted in the Energy Storage Association's 2016 primer on energy storage modeling in IRPs[41] and PGE was invited to present the analysis at industry and policy forums, including the Western Energy Institute's Integrated Resource Planning Forum and the North Carolina Sustainable Energy Association's Energy Storage Working Group. At these forums, utilities around the country shared similar challenges in quantifying the value of energy storage. Key functionality enabled by PGE's approach includes the ability to: co-optimize value across multiple applications and timescales, capture portfolio effects and declining marginal values; quantify monetizable benefits over short timescales in a region without ancillary service markets, and capture utility-specific opportunities and constraints.

In the Energy Storage Potential Evaluation, PGE sought to leverage and update the analysis presented in the 2016 IRP as part of the broader effort to understand the value of energy storage on the PGE system. This appendix summarizes the new ROM analysis conducted to support the Energy Storage Potential Evaluation. It does not address capacity value, locational value, or the interactions between operational and non-operational value streams. These topics are discussed by Navigant in the main body of the report.

ROM Simulation Configuration

PGE quantified the value associated with operational applications in the Energy Storage Potential Evaluation by conducting multiple ROM simulations, each with a different energy storage configuration, and comparing the results to a base case, in which PGE's resource fleet is modeled without the addition of ESSs. Each ROM simulation yields the operational cost of meeting loads and ancillary service requirements across a test year. PGE assumed that the ESSs were capable of providing all of the modeled ancillary services, including: load following, which encompasses the mitigation of forecast errors and renewables integration challenges down to five minutes; regulation; spinning; and non-spinning reserves. The difference in cost between ROM simulations with and without an ESS yielded the net variable cost impact, or the operational value of the ESS. This cost difference reflects the combined value of the co-optimized operational applications—energy arbitrage and the ancillary services listed above. This value is monetized through energy market transactions and variable cost savings throughout the PGE resource fleet, including avoided fuel burn, variable O&M, and unit starts. The operational value

[40] Additional background about ROM and its use in PGE's Variable Renewable Integration Study can be found in Section 7.2.1.1 in PGE's 2016 IRP.

[41] "Including Advanced Energy Storage in Integrated Resource Planning: Cost Inputs and Modeling Approaches," November 2016, http://energystorage.org/system/files/attachments/irp_primer_002_0.pdf.

identified in this analysis therefore assumes that PGE has the ability to control the ESS in coordination with the dispatch of its resource fleet.

PGE evaluated three ESS configurations, including 50-MW ESSs with 2-hour, 4-hour, and 6-hour durations. While the storage investments made by PGE under HB 2193 are capped at 38.7 MW, PGE chose to model 50-MW ESSs in this analysis due to computational considerations common to production cost models, which are discussed below. The Navigant analysis assumes that the benefits of the ESSs determined by ROM scaled linearly to the specific resource sizes considered in the report. PGE's base resource portfolio in ROM reflected the 2021 fleet modeled in the Variable Energy Integration Study (Run 4) described in Section 7.2.1.1 in the 2016 IRP. Hourly and 15-minute energy prices were based on the Reference Case in the 2016 IRP.

Dispatch Behavior

The dispatch behavior of energy storage resources depends on market conditions as well as system demand and the availability and characteristics of other resources in the portfolio. In particular, the extent to which energy storage resources are dispatched to provide reserves depends strongly on the demand for those reserves and the other resources available to provide them. Depending on the cost of providing various reserves with resources within PGE's portfolio, the optimal energy storage dispatch may also prioritize providing some services over others. For example, in time steps[42] when adequate hydro resources are available to provide reserves, the value of providing these reserves with a storage system is small. However, in time steps in which reserves would otherwise be met with thermal resources, providing these services with an ESS provides the opportunity to avoid fuel burn, O&M costs, and potentially unit starts. These economic considerations vary from time step to time step, so the dispatch and provision of reserves provided by the ESS also varies over time. Such considerations also vary by utility depending on market structures as well as the nature of loads and resources available to meet those loads.

Weekly Dispatch Snapshots

Figure B-1 illustrates the simulated dispatch behavior, state of charge, and reserve provisions for a 50-MW, 2-hour ESS with 90% efficiency over the course of a week in January (left panel) and August (right panel) with 15-minute resolution. On the January week, the charging/discharging pattern does not follow a predictable daily trend and the amount of storage capability being utilized (as indicated by the range in the state of charge) changes dramatically from day to day. The regulation reserve provisions tend to follow a diurnal pattern broadly reflective of the daily net load shape, although some time steps deviate from this pattern. Load following reserve provisions change dramatically both across and within days, with no obvious predictable pattern. Note that while the ESS has a 50 MW capacity, reserve provisions can well exceed 50 MW because the ESS is assumed to be capable of switching between charging and discharging modes over very short timescales.[43] Therefore an ESS that is charging at 50 MW could simultaneously provide up to 100 MW of upward reserves and ESS that is discharging at 50 MW could simultaneously provide up to 100 MW of downward reserves.[44] While this assumption is valid for many

[42] Time steps in the ROM modeling were one hour in the day-ahead stage and 15 minutes for other stages.

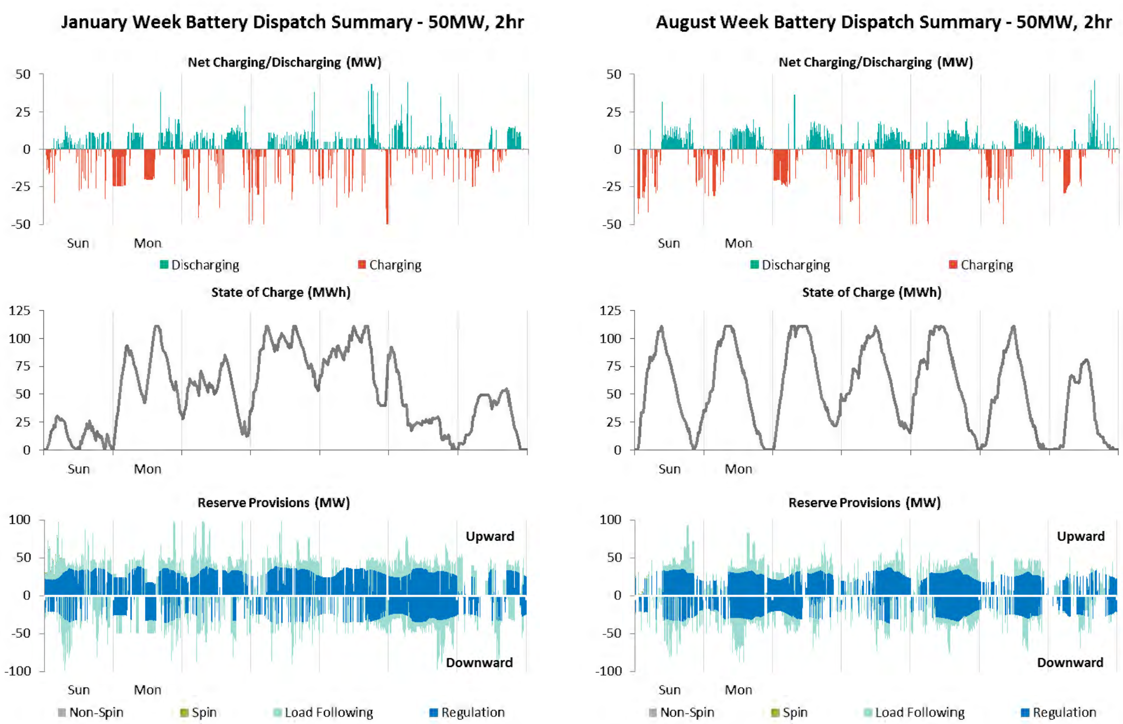
[43] Down to four seconds for regulation.

[44] Load following reserve provisions reflect both load following held in the real-time stage and any differences in ESS dispatch between the day-ahead and real-time stages brought about by forecast errors. This accounting may give rise to periods in which the total reserve provisions appear to exceed the physical capabilities of the ESS even though ESS capability constraints are respected in ROM.

battery technologies, it may not be valid for energy storage technologies with time delays associated with switching between charging and discharging modes—pumped hydro storage, for example.

In contrast, on the August week, the ESS consistently experiences a full or near-full charge and discharge cycle once per day—charging in the early morning hours and discharging in the evening during peak demand conditions. This periodicity is reflected in the state of charge panel. Similar to the January week, the regulation reserve provisions generally follow a predictable daily shape, while the load following provisions are less predictable.

Figure B-1. Energy Storage Dispatch – 50-MW, 2-hour ESS



Source: PGE

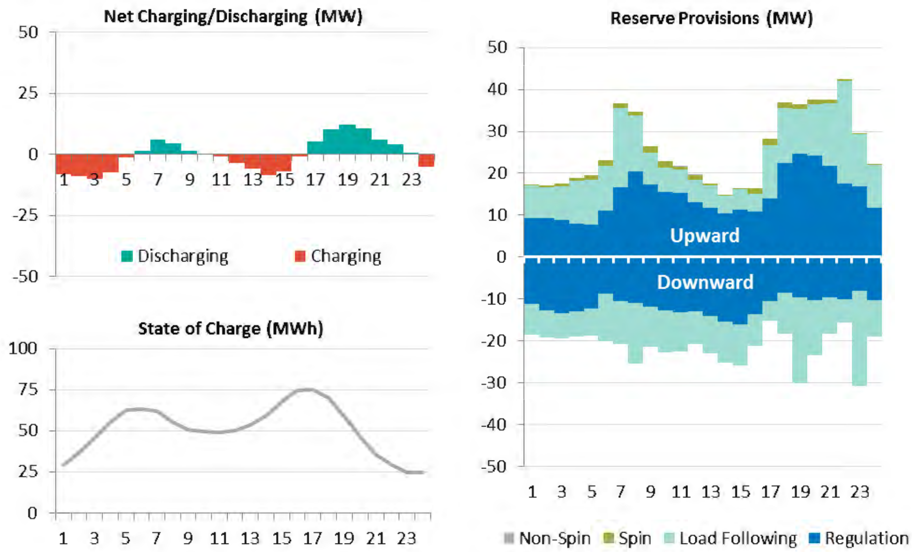
Seasonal Dispatch Patterns

The dispatch behavior can also be summarized on an average basis across seasons to identify general dispatch trends. Average daily dispatch behavior, state of charge, and reserve provisions are shown by quarter in Figure B-2 through Figure B-5.

In the first quarter, the ESS tends to charge in the early morning hours and early afternoon and discharge during the morning and evening peaks, reflecting the load shape. Similarly, average reserve provisions are highest during the morning and evening peaks and during these periods the batteries tend to prioritize providing more upward than downward reserves.

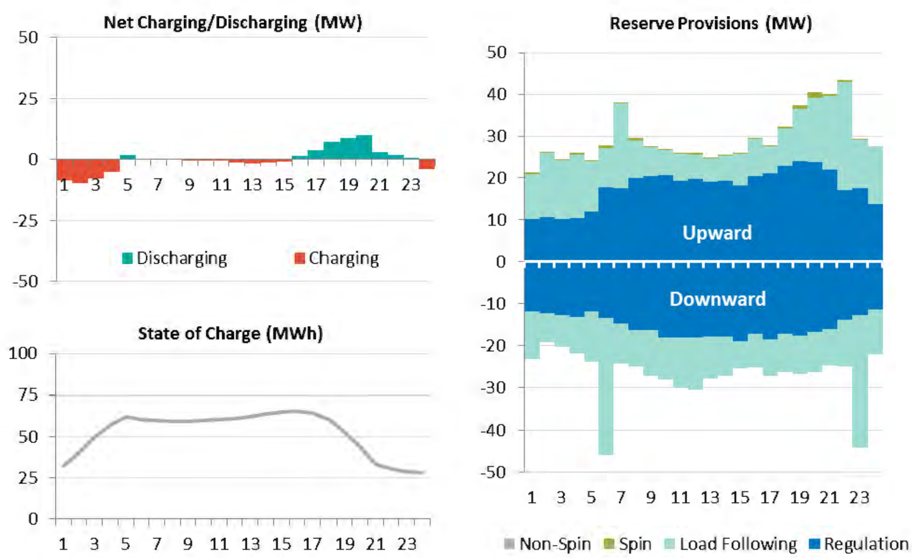
During the second quarter, the average charge/discharge pattern is less reflective of load levels throughout the day and a larger portion of the ESSs' capacity is held to provide both upward and downward reserves. This may be reflective of the constraints on the system imposed by high hydro conditions in the springtime. In addition, the ESS provides significant load following at the on/off-peak boundaries, which helps the system to mitigate the effects of scheduling market purchases in on/off-peak blocks in the day-ahead with imperfect information.

Figure B-2. Q1 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



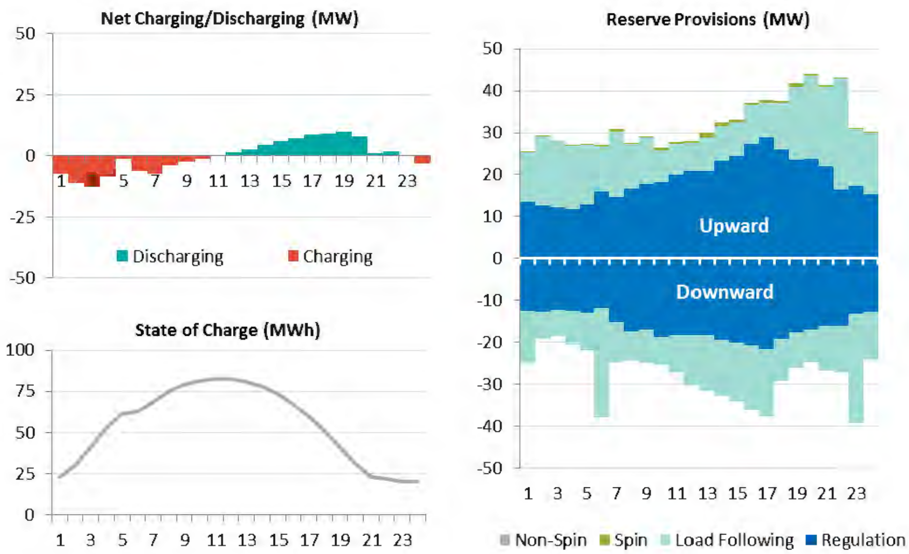
Source: PGE

Figure B-3. Q2 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



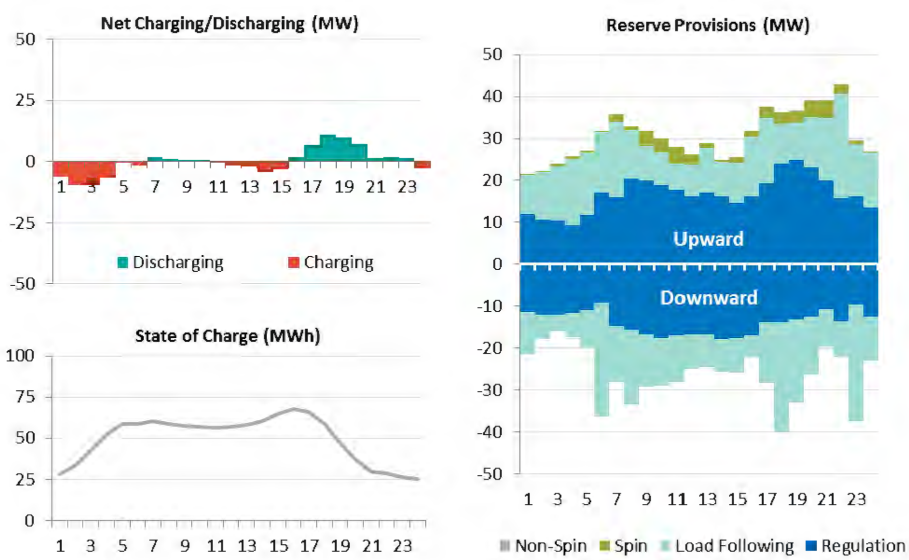
Source: PGE

Figure B-4. Q3 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



Source: PGE

Figure B-5. Q4 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



Source: PGE

In the third quarter, the charge/discharge pattern is largely reflective of the late summer load shape—the ESS tends to charge in the first part of the day and discharge to meet the evening peak. On average, reserve provisions from the ESS are greatest in the third quarter, and the peak provisions for different reserve services are somewhat offset in time, suggesting economics tradeoffs in scheduling these services. For example, while regulation on the ESS peaks in the early evening, load following provisions tend to be higher in the late evening and early morning.

Both charging/discharging patterns and the timing of reserve provisions are similar between the fourth quarter and the first quarter, although the fourth quarter sees a slight increase in the magnitude of reserve provisions on the ESS. While spinning reserve provisions are still relatively small, they tend to be greater in the fourth quarter, which may be reflective of the reduced hydro capability in the fall relative to other seasons.

In all seasons, the daily average charge and discharge patterns are fairly flat relative to the -50 MW to +50 MW potential of the ESS, indicating that if significant ramps are experienced on the ESS, they are not consistently experienced at the same time of day throughout the season. This weak diurnal trend suggests that large ramps are largely driven by dynamic flexibility needs on the system, which vary from day to day and across the day, rather than energy arbitrage opportunities, which typically have a more predictable daily shape. The Reserve Provision panels in Figure B-2 through Figure B-5 corroborate this observation. They show that a significant portion of the ESS capacity is being used to provide regulation and load following reserves. Load following in this context includes both the average upward and downward deviations from day-ahead hourly schedules and fifteen-minute real-time dispatch as well as the additional reserves held in the 15-minute real-time stage to accommodate fluctuations down to the five-minute time scale. The ESS was also found to provide limited spinning reserves and negligible non-spinning reserves due to the ability of other resources in the PGE fleet to provide these services at relatively low cost.

Identified Operational Value

The operational value identified through these simulations is summarized in Table B-1 below. These values are lower than the value identified in the 2016 IRP, in part because the electricity price update reflects increased solar and storage buildout in California and the Southwest.[45] This additional solar generation reduced on-peak prices in the Northwest under Reference Case assumptions. However, the on-peak price reductions were not large enough in the 2021 test year to create the inverted arbitrage opportunities described in California—where ESSs may charge during the day with low or negatively-priced solar and discharge during the high-priced evening peak hours. Instead, the on-peak price reductions experienced in the Northwest and the price-flattened effects of energy storage built elsewhere in the West served to reduce daily price volatility and therefore reduced the value of energy storage in the PGE system relative to prior simulations. PGE anticipates that continued development of renewables will affect the value of energy storage over time and anticipates that higher renewable penetrations are generally likely to increase the value of energy storage in the longer term, despite this near term finding.

Table B-1. ROM Results for 50 MW ESSs

System	Operational Value (nominal $, millions)	Operational Value (2016$/kW-yr)
50 MW, 2 hr	3.27	59.2
50 MW, 4 hr	3.66	66.4
50 MW, 6 hr	3.47	62.9

Source: PGE

The ROM simulations also suggest that the operational value of ESSs may increase slightly as the duration is increased from two hours to four hours; however, this value appears to decline in going from

[45] The energy storage evaluation in the 2016 IRP used electricity pricing from the 2013 IRP Update. The differences in electricity pricing described in this study reflect changes in the WECC-wide fleet between the 2013 IRP Update and the 2016 IRP.

a 4-hour to 6-hour duration. This finding highlights the limitations of production simulation models in resolving small differences in operational value. This is discussed further in the following section.

Model Convergence

All production simulation models, including ROM, require the user to specify a convergence tolerance. Typically, the optimization algorithms run until this tolerance is achieved or until a specified time limit is reached. For complex systems with non-linear or non-convex constraints or cost terms, convergence to the specified tolerance can be challenging, resulting in a tradeoff between runtime and precision. To ensure reasonable runtimes, PGE specified a tolerance of 3%. While most weeks[46] achieve converge to a solution well within the 3% target, some weeks in the simulation instead hit the runtime limit, resulting in reduced precision. PGE has also tested ROM using lower tolerance settings (1%) and longer runtime limits (up to 24 hours per simulated week) and found that while these settings affected whether some weeks converged within the runtime limit, it did not significantly affect the findings for most weeks.

These computational and challenges tend to decline for larger ESSs, as they have larger relative impacts on total operational cost. PGE chose to model a 50 MW ESS in this analysis to balance the desire to model small ESSs for compliance with HB 2193 with these computational convergence challenges.

Effects of Forecast Errors

Even with a much tighter tolerance, multi-stage production simulations may result in negative or lower than expected benefits in some weeks due to forecast errors and commitment constraints. While somewhat counterintuitive, these findings reflect real potential outcomes, not spurious modeling artifacts. Consider, for example, a system in which natural gas nominations must be made in the day-ahead stage. Such a system may determine different commitment schedules for natural gas plants in the day-ahead stage if the fleet includes an ESS than if it does not include an ESS. In real-time, the load or renewable output may deviate from the forecasts that were available in the day-ahead and while some of these deviations are accommodated through reserves, there remains a probability that the schedules established for the fleet without the energy storage system are coincidentally more helpful for balancing the realized renewable output than the schedules established for the fleet with the ESS. Because ROM simulates these forecast errors and the associated impact on dispatch, there are some weeks in which the fleet happens to perform better without an ESS or some weeks in which a 4-hour ESS happens to perform better than a six-hour ESS.

To the extent that forecast errors and convergence tolerances affect the identified value of various ESSs, the value of such ESSs is effectively the same to within the precision of the modeling methods. For this reason, PGE recommended that Navigant use the same operational value for all ESSs of duration equal to or greater than 2 hours. This approach does not preclude long duration storage resources from providing additional value through other applications. For example, a 4-hour ESS provides more capacity value and locational value than a 2-hour ESS.

Differentiating Between Operational Applications

The operational value results suggest that increasing the duration of energy storage resources beyond 2 hours up to 6 hours may not increase the operational value of the ESS within the PGE fleet appreciably. This finding suggests that ancillary services and applications that are associated with short timescales

[46] ROM simulations optimize dispatch across whole weeks.

are the primary drivers of operational value in the near term. This observation is largely consistent with the findings in PGE's 2016 IRP energy storage analysis. PGE did not evaluate ESSs with durations longer than 6 hours, but anticipates that longer duration ESSs may provide additional energy arbitrage and other longer timescale benefits not yet quantified.

PGE conducted additional simulations to explicitly identify the portion of the operational value associated with the various operational applications. This exercise is complex and computationally intensive within a production simulation modeling framework. Because ROM optimizes dispatch across all applications and operational value is monetized through avoided fuel and other variable costs across PGE's fleet, there is no straightforward approach to differentiating value associated with one operational application versus another in a single simulation. Instead, multiple simulations are required in which the ESS is modeled with and without the ability to provide specific services in order to isolate the value of providing those services. Such an exercise requires significant time and computational effort.

To broadly characterize the relative value of the operational applications, PGE conducted an additional ROM simulation to isolate the value of providing regulation, conducted an additional simulation in a simplified dispatch model to approximate the value of energy arbitrage, and supplemented this additional data with observations from the dispatch results to infer the value of remaining operational end uses. The results of the ROM run conducted to isolate the value of providing regulation are summarized in Table B-2. These results indicate that regulation comprises approximately 17% of the total operational value.

Table B-2. ROM Results Isolating the Value of Regulation

System	Operational Value (2016$/kW-yr)
50-MW, 2-hr ESS with all capabilities	59.2
50-MW, 2-hr ESS that cannot provide regulation	49.4
Implied value of providing regulation	**9.9**

Source: PGE

The simplified energy arbitrage-only dispatch simulation of the 50-MW, 2-hour ESS yielded $426,587 of nominal market revenue in 2021, or $7.7/kW-year in 2016$. This comprises 13% of the total value identified in ROM. Importantly, this value represents the potential for the ESS to reduce costs through energy arbitrage in the market, not the actual market revenue associated with the dispatch simulated in ROM. Because the ESS is dispatched to provide ancillary services in ROM, a portion of this revenue is foregone in the ROM simulations in order to provide these other, higher value services.

PGE assumed that the load following value could be approximately isolated by subtracting the energy arbitrage and regulation value from the total operational value. This assumption was based on the observation that the ESSs rarely provided spinning or non-spinning reserves in the ROM dispatch simulations due to the ability of other low cost resources within PGE's fleet to provide these reserves. The resulting approximate break out of the value associated with operational end uses is summarized in Table B-3.

As the analysis shows, the majority of the operational benefits of the ESS are associated with providing load following. This finding comports with expectation as load following reserves allow the fleet to mitigate forecast errors of both the load and renewables and to provide sub-hourly balancing down to the five-minute time scale. This finding is also consistent with the observation that increasing the duration to provide longer term services does not appreciably affect the operational value of the ESS.

Table B-3. Decomposition of the Value of Operational Applications

End Use	Operational Value (2016$/kW-yr)	% of Total
Energy Arbitrage	7.7	13%
Load Following	41.6	70%
Regulation	9.9	17%
Spin & Non-spin Reserves	0.0	0%
All operational applications	**59.2**	**100%**

Source: PGE

Conclusions

The analysis described in this report represents the continued evolution of PGE's energy storage modeling efforts and provides a snapshot given the information and modeling capabilities available today. The findings are specific to PGE and the resource portfolios modeled and are therefore likely to differ from other utilities and/or markets.

In the future, the operational value of energy storage resources will be affected by PGE's loads and resource fleet, market conditions and new market structures (e.g., the Western Energy Imbalance Market), as wells as new technologies within PGE's service area (both utility-scale and distributed). In particular, resources that provide flexibility to the system, including demand response, may erode some of the future value of energy storage if they can provide the same services over multiple timescales. Conversely, resources that require more flexibility from the system, such as additional wind and solar, may increase the future value of energy storage. As described in the 2016 IRP, the marginal value of energy storage may also tend to decrease on a given ESS as the need for additional flexibility reduces with the size of the energy storage fleet.

PGE will continue to assess these system-level factors within the Integrated Resource Planning process and the Company seeks to incorporate updates to the energy storage analysis as new information becomes available. PGE will also work to refine its modeling capabilities to improve resource characterization, runtimes, and convergence where possible. Through these efforts, PGE aims to be a leader in energy storage evaluation and to continue to provide novel insights into the potential for energy storage resources to provide value to the system.

B.3 Integrated Planning Tool (IPT)

Additional details for the IPT are provided in the attached report prepared by BIS Consulting for PGE.

Date	April 18, 2017
From	Darin Johnson
To	Brian Spak, PGE
Copy	Jon Robinson, PGE Josh Mullins
Regarding	Report on life-cycle cost analysis of energy storage and locational benefits.

BIS Consulting is pleased to submit this report on cost/benefit assessment of energy storage options and the locational benefits. This report is based on life-cycle cost analysis using the Integrated Planning Tool (IPT), developed by the Strategic Asset Management group (SAM) at PGE. It documents estimated benefits of energy storage in terms of avoided outage cost to customers and extended life of assets.

This work was carried out by a project team comprising representatives from T&D, Planning, SAM, and BIS Consulting. Deliverables include this report, and specialized versions of the IPT developed to support the analysis.

Background

PGE intends to install energy storage systems (i.e., batteries) at one or more locations to satisfy Oregon HB 2193. There are multiple benefits of energy storage, one of which is reduced outage risk to customers. Other benefits are outside the scope of this study.

Reduced outage duration produces benefits in two ways.

- The future cost to customers due to outages is reduced since power can be restored more quickly. This benefit is quantified based on standard outage cost assumptions utilized by SAM for all benefit/cost analyses of this type.
- Reduced consequence of failure, and thereby reduced risk, extends the economic life of aging assets, allowing PGE to delay capital expenditures.

PGE has identified three possible locations for energy storage.

- At substations connected to the bus. This option allows for restoration of power in cases of lost transmission supply.
- At multiple locations along a given feeder trunk, in conjunction with feeder automation. This allows restoration of power for any outage at the substation, and restoration of most customers on the feeder for any feeder-level outage.
- Customer-sited. This option keeps selected customers on-line for any outage on the distribution system.

This analysis is one step in a broader process of benefit/cost/locational assessment for battery options. The intent of this work is to provide input to a more comprehensive discussion of benefits to be performed by others.

Sources of information

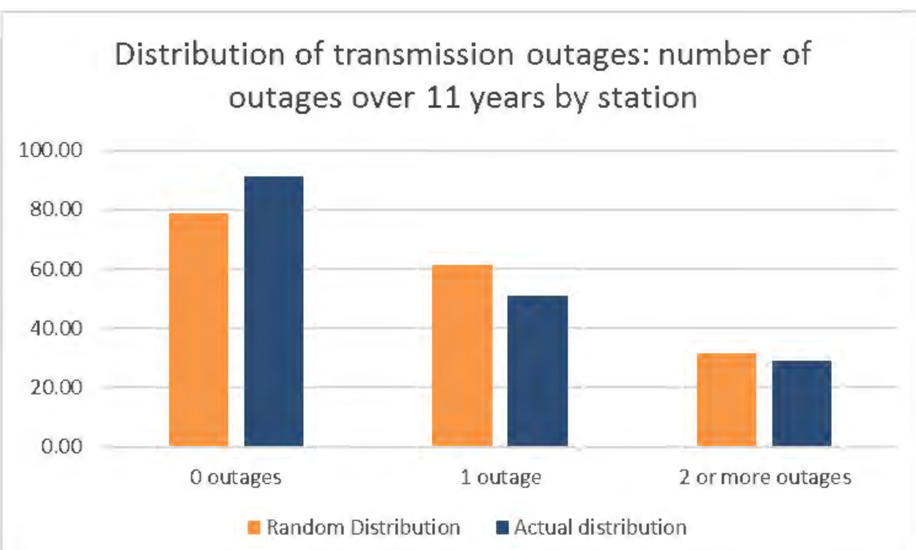
This analysis makes use of two major sources of information.

SAM tools, including IPT
The first is the suite of risk-based life-cycle cost tools, which includes the IPT, developed by SAM. These tools quantify risk due to failures, including the cost to customers due to loss of power. The cost of outages is calculated based on customer survey results, which are incorporated into all of SAM's risk analyses. These tools are used to calculate life-cycle cost, including outage risk and future asset replacements, with or without batteries, per the assumptions described below. The results are expressed in net present values, assuming cyclic replacement of aged or failing batteries (i.e., the benefits extend far into the future).

System Disturbance Database (SDDB) for loss-of-transmission events
The second source of data is the SDDB and the outage management system. These databases include cause codes, which were used to estimate the frequency of loss-of-transmission events over the past 11 years; the outage validation was completed by the T&D Planning team, a review for inappropriately coded events was done by T&D.

The team expected that some substations would be more susceptible to loss-of-transmission events than others, and that this increased exposure will cause those substations to be more attractive locations for battery installation. However, statistical analysis of the data does not support rejecting the null hypothesis – that loss-of-transmission events are randomly distributed. To see this we compared the actual distribution of how many substations experienced zero, one, or two or more outages over the 11-year period with what we would expect the distribution to look like. The result is shown in the graph below.

Comparison of actual distribution of loss-of-transmission outage counts by substation with a random distribution



A Chi-Square test returns a value of 0.14, which is not enough to indicate the distribution is non-random. Therefore, we have assumed that all substations face the average probability of loss of transmission.

The team deemed the duration data for loss-of-transmission outages not reliable enough for use, so the average duration for all such outages was used.

Substation option

A battery installed at the substation bus will allow PGE to restore power to all customers in the event of an outage at the bus due to failure of the transformer or loss of transmission supply. It will not provide reliability benefits in case of an outage at the bus itself (e.g., wildlife in the buswork, or any feeder-level outages, such as cable failure or non-asset failures from weather, trees, or animals). Assumptions include the following.

- Batteries are installed at each bus at the substation.
- The batteries will restore power in case of loss of transmission supply or substation transformer failure; bus- and feeder-level outages are unaffected.
- Three sizes are evaluated: 2-hour, 4-hour, and "infinite." These define the number of hours customers can be served by the battery. For example, under the two-hour-battery scenario, any outage less than two hours will be reduced to a momentary. Longer outages will be reduced by the duration of the battery.
- Based on historical data, the annual probability of a loss of supply event is 7.1%. Statistical analysis of the historical data suggests that this probability applies approximately evenly to all substations. Based on discussions among the project team, we have assumed that all loss of transmission events will have a duration of 248 minutes, which is the system average.
- Transformer failure probabilities and failure scenarios (i.e., durations) are based on the assumptions by the T&D team during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets at each substation under each scenario. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for that length of time (i.e., 2, 4, or "infinite" hours).
- The benefits are shown in "per kWh" terms, to normalize for the load at each substation. Although the total benefit increases with larger batteries, the benefit per kWh drops because the incidence of longer durations outages that could take advantage of the capacity is less likely.
- If the batteries are used for other purposes, such as peak shaving, and are not fully charged, you will have to interpolate to estimate the actual benefit.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average load at the substation multiplied by the assumed battery duration (12 hours used for "infinite" battery).

The results are heavily stratified, with a few substations showing significant benefits. These are generally substations with a high percentage of commercial load, which has a higher assumed cost per lost kWh than residential or industrial load.

Feeder option

Feeder batteries will be installed at multiple locations along the length of the feeder. Smart switches will also be installed, so that power can be restored to all customers except those in the same zone where the outage occurs. For example, if a tree falls into the line halfway down the feeder, the customers between the substation and the switch *upstream* from the fault and customers downstream of the switch *downstream* of the fault will be restored after a momentary outage. Customers in the same zone as the fault will face a sustained loss of supply. In case of a loss of supply at the substation, all customers will be restored.

Assumptions include the following.

- Sufficiently sized batteries are installed at two locations on each feeder (i.e., three zones), including the substation. Feeder load is assumed to be distributed evenly among the zone, and all necessary automation is assumed to be installed.
- The batteries will fully restore power in case of loss of transmission supply or substation transformer failure. Two thirds of customers will be restored after a momentary outage for any feeder-level event. Feeder-level events include trunk-asset failures and non-asset risk due to weather, vegetation, animals, etc. Non-asset risk on the taps is assumed to be unaffected.
- Three sizes are evaluated: 2-hour, 4-hour, and “infinite.” These define the number of hours customers can be served by the battery. For example, under the two-hour-battery scenario, any outage less than two hours will be reduced to a momentary. Longer outages will be reduced by the duration of the battery.
- Probabilities and failure scenarios (i.e., durations) for all asset failures and non-asset events are based on the assumptions developed by T&D during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets at each substation under each scenario. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for that length of time (i.e., 2, 4, or “infinite” hours).
- The benefits are shown in “per kWh” terms, to normalize for the load at each feeder. This represents to the total average load on the feeder, so the total required battery capacity for the three-battery system.
- If the batteries are used for other purposes, such as peak shaving, and are not fully charged, you will have to interpolate to estimate the actual benefit.
- The per-kWh benefit is substantially higher for feeder-level batteries than for batteries at the substation. The reason is that the feeder batteries will restore power in the event of a non-asset risk event (e.g., weather, vegetation, animals) on the feeder; these events represent the majority of outage risk in the system.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average load on the feeder multiplied by the assumed battery duration (12 hours used for “infinite” battery).

As with substations, the results are stratified, with a few feeders showing significant benefits. These are generally feeders with a high percentage of commercial load, which has higher assumed cost per lost kWh than residential or industrial load.

Customer option

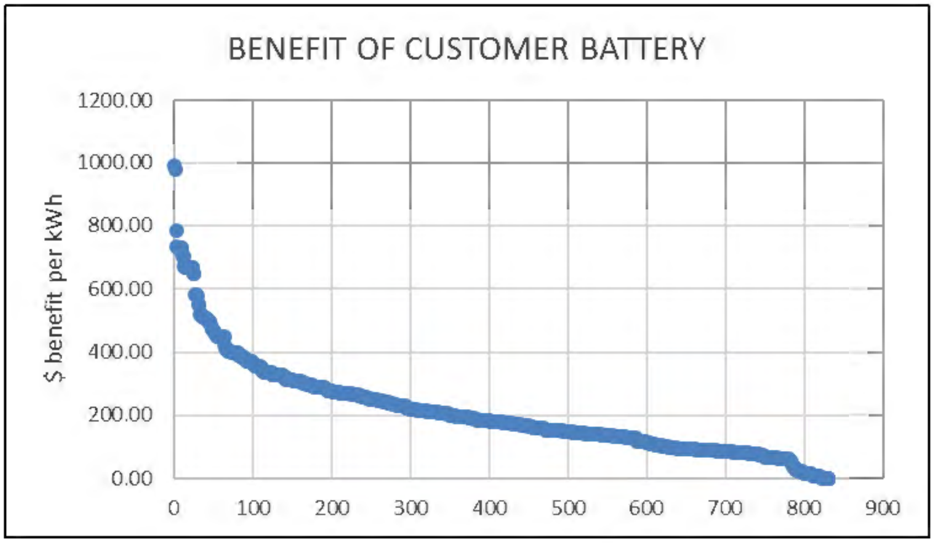
The final option considered is a customer-sited battery that will restore power after any outage in the transmission or distribution system. Assumptions include the following.

- Batteries are installed near the meter for commercial customers identified by PGE.
- Alternate service or backup generation are not available.
- The batteries will fully restore power for any outage to the customer.
- These customers are fed from the trunk, so there are no relevant risks from assets or non-asset events on the tap to consider.
- Only the “infinite” battery size is evaluated. This will generally be a 4-hour battery, although more capacity may be required for customers on rural or remote feeders where outage durations are longer.
- Probabilities and failure scenarios (i.e., durations) for all asset failures and non-asset events are based on the assumptions by T&D during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets serving key customers. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for the full duration of any outage.
- The per-kWh benefit for this option is higher than either the substation or feeder option. There are two reasons for this: first, the battery restores power to all the customers it serves (generally one) after any outage. Second, the battery serves only commercial customers, who benefit most in economic terms from reduced outage duration.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average customer load multiplied by the average duration of outages at the feeder: 4 hours for urban, 5 hours for rural, 6 hours for remote. The graph below shows the estimated benefit from avoided risk each customer in per kWh to normalize for load.



Interpretation of results

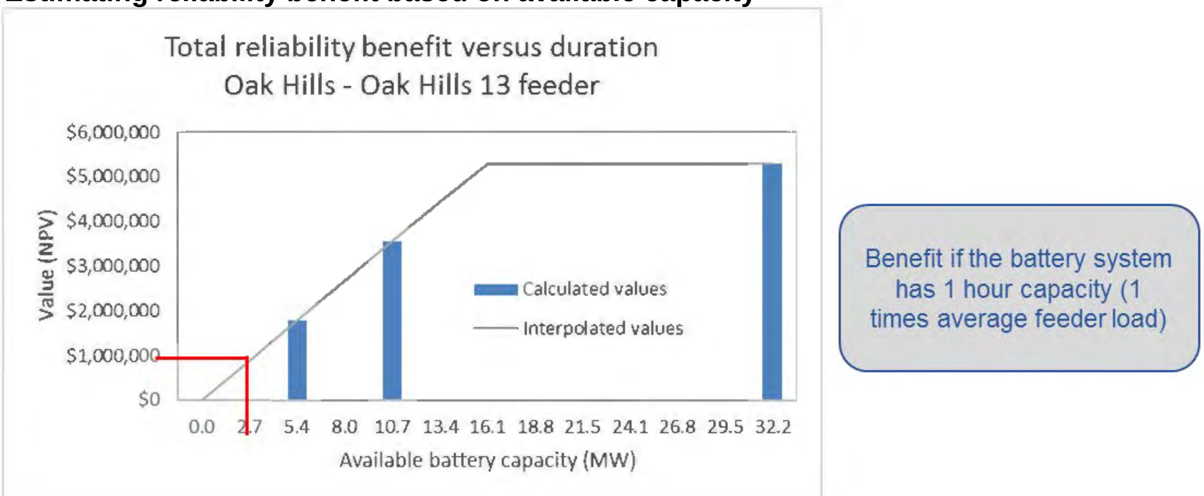
Incorporation into comprehensive model

These results are intended to be integrated into a more comprehensive cost/benefit model developed by PGE. Depending on how the batteries will be used, the available capacity may be less than the full capacity of the battery at any given time. In order to estimate the benefit based on actual expected capacity, we recommend you consider the following procedure.

- Assume a linear fit of the value as a function of capacity from zero (the base case) through the four-hour option.
- Extend this line until it reaches the benefit of the "infinite battery, which is the upper limit.
- Graph this curve against duration multiplied by the average load of the feeder or substation.
- Use this graph to pick off benefits for as many scenarios as necessary to populate the benefit/cost model.

An example is show below for the Oak Hills – Oak Hills 13 feeder, which has an average load of 2.7 MW.

Estimating reliability benefit based on available capacity



If the battery is expected to have eight hours' capacity 75% of the time ($5.3 million benefit) and one hour's capacity 25% of the time ($1 million benefit), then the expected benefit will be approximately 5.3 x 75% + 1.0 x 25% = $4.0 million.

Additional recommendations

Recommended additional steps include the following.

- Continued review and vetting of the results to ensure they conform with expectations.
- Before spending decisions are made, a pre-scoping task to ensure quality results is needed. This should include validation of assumptions, system configuration, and historical outage and other data.
- Additional runs for other scenarios or for sensitivity analysis may be needed. We recommend that you contact us for support. The model used is a specialized version of the IPT, developed specifically for this analysis; training on other SAM tools may not be sufficient for easy use of this one.

We appreciate the opportunity to work with your group on this assessment. Please do not hesitate to contact us with any questions.

Summary of PGE's Energy Storage RFI

PGE issued a Request for Information (RFI) on May 23rd, 2016 to assist in understanding and evaluating the capabilities of companies that can function as the engineering, procurement, and construction (EPC) primary contractor for energy storage projects. The RFI requested company professional background, financials, energy storage program development experience, technology performance, performance guarantees, and references. Responses were collected until June 10th, 2016. PGE received 27 responses from:

1. 1Enregy
2. ABB
3. AES
4. AMS
5. Burns and McDonnel
6. Eaton
7. Edison Energy
8. Enerdel
9. Eos Energy Storage
10. GCN
11. GI Energy
12. Lockheed Martin
13. LSP
14. Mega Point Energy, LLC
15. NEC Energy Storage
16. Renewable Energy Systems Holding Ltd
17. S and C Electric
18. SolarCity
19. Stem
20. Stornetic
21. Sumitomo
22. SunPower
23. Sunverge
24. Tesla
25. TrinaBEST
26. UET
27. Younicos

Responses were evaluated on the strength of the organization and personnel, financial viability, experience and technical competence, preferred storage technology, the ability to provide performance guarantees, and references.

The majority of respondents focused on larger, grid-scale storage solutions. Less than 1/3 of respondents provided information focused on customer-sited storage installations.
Of the 27 responses, 19 proposed lithium-ion battery technology, three proposed flow-battery technology, three were technology agnostic, one proposed zinc battery and one lithium air battery technology. Seven responses were from storage manufacturers. Most respondents were willing to negotiate with PGE to create capacity guarantees. All but seven respondents were willing to share generalized pricing information without a non-disclosure agreement. However, costs were difficult to compare because of the inconsistent inclusion of additional equipment (e.g. power conversion systems).

The RFI provided PGE a relatively short list of companies that could likely engineer, procure, and construct one or many energy storage systems to meet the HB 2913 mandate. From a high-level, PGE was impressed by both the quality and quantity of responses, and has benefited from the responses and follow-up discussions with many of the vendors.

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Brad Carpenter. I am a Senior Analyst in Integrated Resource Planning (IRP) for Portland General Electric Company (PGE). My qualifications appear in Section IV of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to Public Utility Commission of Oregon (OPUC or Commission) Order No. 17-357 in Docket No. UM 1716, requesting that utilities file proposed resource value of solar (RVOS) element values, along with narrative descriptions and workpapers, as applicable. My testimony will focus on PGE's proposed values for avoided environmental compliance costs (Environmental Compliance) and will discuss potential future development of the avoided renewable portfolio standard (RPS) compliance element.

Q. Has the Commission given specific guidance regarding the calculation of Environmental Compliance and RPS element values?

A. Yes. In Commssion Order No. 17-357, the Commission provided the following instructions with regard to calculating the Environmental Compliance and avoided RPS elements:

1. Environmental Compliance – "We direct the utilities to calculate a value for informational purposes, to be used as a placeholder in their initial RVOS filings. The utilities should estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit with the carbon regulation

assumptions from their [IRP]. We will decide on the application of this element based on implementation of RVOS at a later time."[1]

2. Avoided RPS Compliance – "We direct the utilities to assign a zero value as a placeholder for this element in their initial RVOS filings. However, we will revisit the proper inputs for this element, and will endeavor to assign a methodology before the end of Phase II. At this time we find that the value or cost of avoided RPS compliance ovrelaps with several other pending dockets."[2]

[1] Order No. 17-357, pg 13
[2] Order No. 17-357, pg. 13

II. Environmental Compliance

Q. Has PGE calculated a value for the avoided cost of environmental compliance for this docket?

A. Yes, workpapers supporting the calculation for the avoided cost of future carbon compliance are included with this filing. The resulting values are included as an input in the Energy and Environmental Economics (E3) model included in this filing.

Q. Please provide a narrative description of the calculation, and explain what the calculation is designed to measure.

A. The calculations underlying the environmental compliance values are designed to reflect the difference in the energy value of a solar resource under an environment with carbon prices and without carbon prices. We utilized a generic solar tracking facility for this analysis with a 2018 commercial operation date, which assumes the same characteristics and costs as were utilized in PGE's 2016 IRP. We also utilized a 25 year period, which is the assumed project life of a resource in RVOS. Further, the nominal after tax weighted average and real levelized cost of capital and inflation assumptions as used in PGE's 2016 IRP were applied to our calculation for the avoided cost of environmental compliance. Lastly, the value proposed is in 2017 dollars.

Q. How did you calculate the energy value in PGE/301?

A. Energy value is calculated on an hourly basis as the product of the hourly generation from the solar resource and the hourly wholesale electricity market price for that hour.

PGE simulates wholesale electricity market prices for the Pacific Northwest using the software AURORAxmp (AURORA). Prices are calculated hourly within the Western Electricity coordinating Council (WECC) and depend on several input assumptions, among which is the stack of available resources in that hour and the cost of carbon emissions. AURORA computes hourly prices as the dispatch cost of the marginal resource used to meet load.

Q. What is the resource type used as the "marginal" unit in the AURORA simulation?

A. There is no single marginal resource selected as the comparator for the purpose of building the avoided Environmental Compliance element. Rather, the AURORA simulation selects on an hour-by-hour basis what the marginal generating unit would be – both with and without a national carbon price.

Q. What source did PGE utilize for its national carbon price assumptions?

A. PGE utizlied the mid national carbon price forcast from Docket No. LC 66 – PGE's 2016 IRP. The forcast was published by Synapse Energy Economics in its "Spring 2016 National Carbon Dioxide Price Forecast." This forecast is included as PGE/501. For further information, please see Chapter 3 in PGE's 2016 IRP.

Q. Are the carbon prices utilized by PGE synonymous with the social cost of carbon?

A. No. These are distinctly different methodologies, and although they both place a price on carbon emitted from the generation of energy, they measure two different impacts.

Social cost of carbon (SC-CO_2) is defined by the United States Environmental Protection Agency (EPA) as the "comprehensive estimate of climate change damages and includes, among other things, changes in net agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs." [3]

[3] https://www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf

The Synapse carbon price forecast on the other hand reflects compliance with both Synapse-modeled carbon regulations and climate goals as discussed in Section 3.1.3.2 of PGE's 2016 IRP.

Q. Why did PGE estimate the cost of carbon compliance based on the IRP values, rather than SC-CO_2, as defined by the EPA?

A. PGE estimated the cost of carbon as directed by the Commission in Order Nos.17-357 and 15-296. Commission Order No. 17-357 directs utilities to "estimate the avoided cost based on a reduction in carbon emissions…[U]tilities should use the carbon regulation assumptions from their IRP." Commission Order No. 15-296 states that the Commission "[W] ill only consider elements that could directly impact the cost of service to utility customers. For example, we would consider the potential financial costs to utilities of future carbon regulation. On the other hand, for example, we will not consider job impacts of solar development."

Q: Does PGE have any other concerns with the Environmental Compliance element?

A: While PGE believes this is a reasonable manner in which to calculate the Environmental Compliance element of the RVOS, it is important to note this is a preliminary approach to capturing the value of Environmental Compliance. Further investigation may provide insights that demonstrate another approach better captures the value of environmental impacts. For example, additional review may be necessary to consider interactions with other elements and to evaluate the proper payment structure.

PGE also requests that the calculation of the Environmental Compliance for purposes of the RVOS -- especially during this first calculation of an RVOS price -- not be precedential in nature, and not be used in other dockets.

III. RPS Compliance

Q. Has PGE estimated the value of the avoided RPS Compliance element?

A. No. Consistent with the direction given in Commission Order No. 17-357, PGE has set the value in the E3 model to zero, and plans to participate in further proceedings to determine the value of this element.

Q. Is there the potential for overlap between the avoided RPS Compliance element and the Environmental Compliance element?

A. Yes. The primary instrument used to comply with the RPS -- the retirement of a renewable energy certificate (REC) associated with renewable generation -- is currently understood to encapsulate all environmental attributes of the generation produced. This could theoretically be interpreted to include carbon compliance, but in the absence of carbon price legislation in Oregon, this is a difficult question to answer.

There is also potential overlap with other elements, such as the Market Price Response. As noted earlier in my testimony, additional review may be necessary to consider interactions with other elements and to evaluate the proper payment structure.

IV. Qualifications

Q. Mr. Carpenter, please state your educational background and experience

A. I received a Bachelor of Arts in Economics from Bucknell University and a Masters of Business Administration from Carnegie Mellon University in 2009. I began my current role within PGE's IRP team in March of 2017. Prior to my current role, my career has focused on both equity and credit research within the energy sector, as well as investment banking within the energy sector. I am a holder of the right to use the Chartered Financial Analyst® designation.

Q. Does this conclude your testimony?

A. Yes.

Spring 2016 National Carbon Dioxide Price Forecast

Updated March 16, 2016

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AUTHORS' NOTE

On February 9, 2016, shortly after the release of the original version of this report, the U.S. Supreme Court issued a stay on the Clean Power Plan—an unprecedented step as litigation against the rule had not yet been heard at the D.C. Circuit Court of appeals. A stay is essentially a judicial pause on the implementation of a regulation while challenges work their way through the court system.

The stay on the Clean Power Plan does not impact Synapse's long-run forecast of carbon dioxide prices, but could affect the price in earlier years. Despite the substantial uncertainty posed by the stay, many states and system operators have continued Clean Power Plan planning activities. At this point we have not found sufficient evidence to change the forecast presented in this report. This note regarding the stay on the Clean Power Plan is the only change from the original report.

CONTENTS

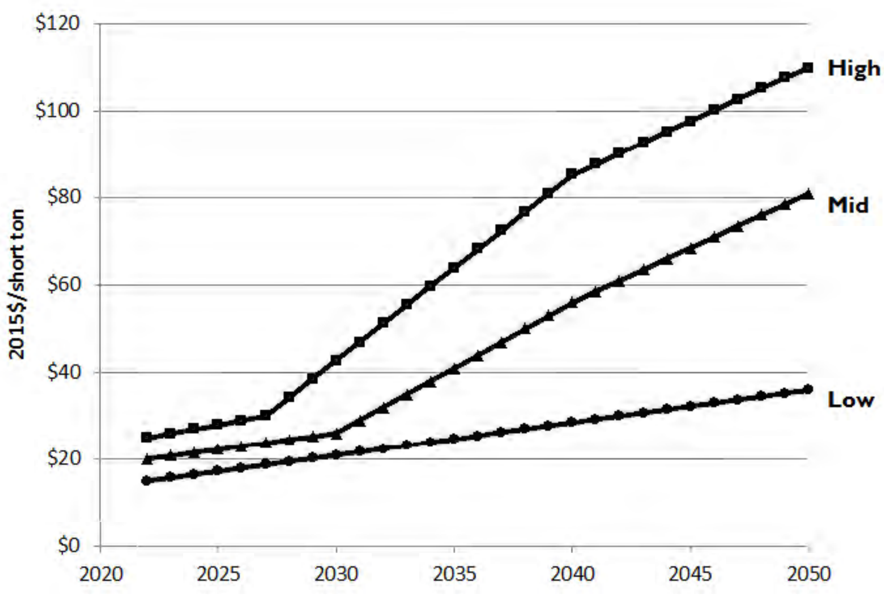
EXECUTIVE SUMMARY

Prudent and reasonable planning requires electric utilities and other stakeholders in carbon-intensive industries to make their best efforts to estimate the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. In the regulatory context, this means assigning a number to the future costs of compliance with emissions-related policies. However, forecasting a CO_2 price can be difficult. Federal government limits on CO_2 emissions from new and existing power plants, regional and state policies, other environmental regulation of power plants, and future regulations necessary to meet science-based climate goals all impact the cost of fossil fuel-powered electric generation. A CO_2 price forecast acts as a proxy for these expected costs.

The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable. Such environmental changes are expected to result in damages to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear, and policymakers have been responding accordingly. To make sound investment decisions, utilities must follow suit by considering existing, proposed, and expected future regulations. First and foremost among these is the Clean Power Plan, the U.S. Environmental Protection Agency's (EPA) regulation of CO_2 emissions from existing power plants under Section 111(d) of the Clean Air Act finalized by the in October 2015. While the Plan does not specify a price on CO_2 *per se*, it nonetheless will result in an "effective" price of CO_2—an important consideration in planning for both utilities and states.

Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2022 to 2050. In these forecasts, the Clean Power Plan together with other existing and proposed federal regulatory measures place economic pressure on CO_2-emitting resources. The stringency of these forecasts is explained later.

Figure ES-1: Synapse 2016 CO_2 Price Trajectories



Source: Synapse Energy Economics, Inc. 2016.

This 2016 report provides an updated CO_2 price forecast and supplements Synapse's 2015 Carbon Dioxide Price Forecast with the most recent information on federal regulatory measures, state and regional climate policies, and new Synapse modeling analysis.[1] The Synapse CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility integrated resource planning (IRP) and other electricity resource planning analyses. We have reviewed and updated our summary of the key regulatory developments in the past year, including not only the Clean Power Plan but a number of complementary policies.

Key Assumptions

This report includes updated information on federal regulations, state and regional climate policies, and utility CO_2 price forecasts, as well as our own analysis of the final Clean Power Plan. The Low, Mid, and High Synapse CO_2 price forecasts presented here have some similarity to those in our 2015 report and extend to 2050 to reflect long-term climate targets. Synapse's CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term legislation passed by Congress to reach science-based emissions targets, will result in significant pressure to decarbonize the electric power sector. Key assumptions of our forecast include:

- Near-term climate policy actions reflect a regulatory approach, for example, under Sections 111(b) and 111(d) of the Clean Air Act.
- A federal program establishes targets more stringent than the Clean Power Plan.
- Future federal legislation sets a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
  - New technological opportunities that lower the cost of carbon mitigation;
  - Lower gas prices that reduce the costs of potential policies;
  - A continuation of executive actions taken by the President that spur demand for congressional action;
  - The inability of executive actions to meet long-term emissions goals;
  - A Supreme Court decision making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
  - Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

[1] Luckow P., E.A. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2-emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that the combination of federal regulatory measures and regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent and reasonable utility planning requires that utilities take this cost into account when engaging in resource planning, particularly for investment of capital in long lived assets.

Study Approach

In this report, Synapse reviews several key developments that have occurred over the past 12 months. These include:

- Federal regulatory measures to limit CO_2 emissions from existing power plants and an updated proposal for new power plants (the Clean Power Plan);
- The most recent auctions under both Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and California's AB 32 Cap-and-Trade program; and
- Synapse's analysis of carbon price forecasts from 115 recent utility filings.

Synapse's 2016 CO_2 Price Forecast

Based on analyses of the sources described in this report, and relying on our own judgment and experience, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2022 to 2050. In these forecasts, the Clean Power Plan together with other existing and proposed federal regulatory measures place economic pressure on CO_2-emitting resources in the next several years. The likely result will be relatively more expensive operating costs for high-carbon-emitting power plants. In any state other than the RGGI region and California, we assume a zero carbon price through 2021. Beginning in 2022, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. We assume smooth allowance trading among large groups of states. The Clean Power Plan is followed later by a more stringent federal policy in the Mid and High cases. The CO_2 prices presented here are forecasts of "effective" prices of CO_2 which may or may not take the form of market-based allowances (see Section 3 for a discussion of different types of CO_2 prices).

- The **Low case** forecasts a CO_2 price that begins in 2022 at $15 per ton.[2] It increases to $21 in 2030 and $36 in 2050, representing a $23 per ton levelized price over the period 2022-2050. This forecast represents a scenario in which Clean Power Plan compliance is relatively easy, and a similar level of stringency is assumed after 2030. Low case prices are also representative of the incremental cost to produce electricity with natural gas as compared to coal, as indicated in the Energy Information Administration's 2015 Annual Energy Outlook.

- The **Mid case** forecasts a CO_2 price that begins in 2020 at $20 per ton. It increases to $26 in 2030 and $81 in 2050, representing a $38 per ton levelized price over the period 2022-2050. This forecast represents a scenario in which federal policies are implemented with challenging but reasonably achievable goals. Clean Power Plan compliance is achieved and science-based climate targets mandate at least an 80 percent reduction in electric section emissions from 2005 levels by 2050.

- The **High case** forecasts a CO_2 price that begins in 2022 at $25 per ton. It increases to approximately $43 in 2030 and $110 in 2050, representing a $55 per ton levelized price over the period 2022-2050. This forecast is consistent with a stringent level of Clean Power Plan targets that recognizes that achieving science-based emissions goals by 2050 will be difficult. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2027. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector. Other factors that may increase the cost of achieving emissions goals include: greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

[2] "Tons" refer to short tons throughout this report.

1. Overview

Estimating the future costs of complying with policies and regulations related to carbon dioxide (CO_2) emissions is now firmly accepted best practice for prudent and reasonable energy planning. Electric utilities and other stakeholders in carbon-intensive industries have the responsibility to capture these costs to the best of their abilities when evaluating resource investment decisions with multi-decade lifetimes. The most prevalent way to do this is through the use of a CO_2 price forecast, an undertaking that is inherently difficult due to uncertainty about the future. To make sound investment decisions, utilities must consider existing regulations as well as proposed and expected future regulations.

To facilitate good planning practices, Synapse develops its CO_2 price forecasts based on the data sources and information presented below. The forecasts reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The current forecast contains updates to Synapse's 2015 CO2 price report based on developments from the past 12 months including, importantly, the U.S. Environmental Protection Agency's (EPA) newly finalized Clean Power Plan. Released under Section 111(d) of the Clean Air Act, the Clean Power Plan regulates CO_2 emissions from existing power plants.

The following evidence has guided the development of the Synapse 2016 forecasts:

- **Regulatory measures limiting CO_2 emissions from new and existing power plants have been finalized**. In October 2015, EPA finalized emissions standards for new and existing power plants under Section 111(b) and 111(d) of the Clean Air Act. New Source Performance Standards limit fossil fuel-powered generation built after January 8, 2014. The Clean Power Plan applies to existing fossil fuel-powered electric generation with the goal of reducing electric-sector emissions between 2022 and 2030. These actions represent an effective price on CO_2 that will affect utility planning and operational decisions.

- **Ongoing analysis of the Clean Power Plan suggests a wide range of possible CO_2 prices.** Important factors include the level of regional cooperation, the availability of renewable energy and energy efficiency, and natural gas prices.

- **Environmental regulation can, and often does, evolve incrementally over time**. Initial awareness of environmental damages, followed successively by measurement and study of the damages and initial attempts to regulate the responsible sources (and associated debate and legal challenges), are eventually followed by more detailed or nuanced regulations. For climate change and greenhouse gas emissions from the electric power sector in the United States, this process has been in progress for several decades. In our view, the trends are likely to continue as increasingly apparent risks demand regulatory and policy responses.

- **State and regional action limiting CO_2 emissions is ongoing and growing more stringent**. In the Northeast, the Regional Greenhouse Gas Initiative (RGGI) CO_2 cap has been tightened, and recent auctions have used all available cost-containment reserves, resulting in higher CO_2 prices for electric generators in the region. California's AB 32 Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many allowance auctions, has been successfully defended against numerous legal challenges, and was expanded to include natural gas and transportation fuels in 2015.

- **A price for CO_2 is required in federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement by including a "social cost of carbon" in rulemakings such as fuel economy and appliance standards.
- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of CO_2 prices reported in Section 6 suggests that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

This report presents Synapse's 2016 Low, Mid and High carbon dioxide (CO2) price forecasts, along with the evidence assembled to inform these forecasts. It is organized in the following sections:

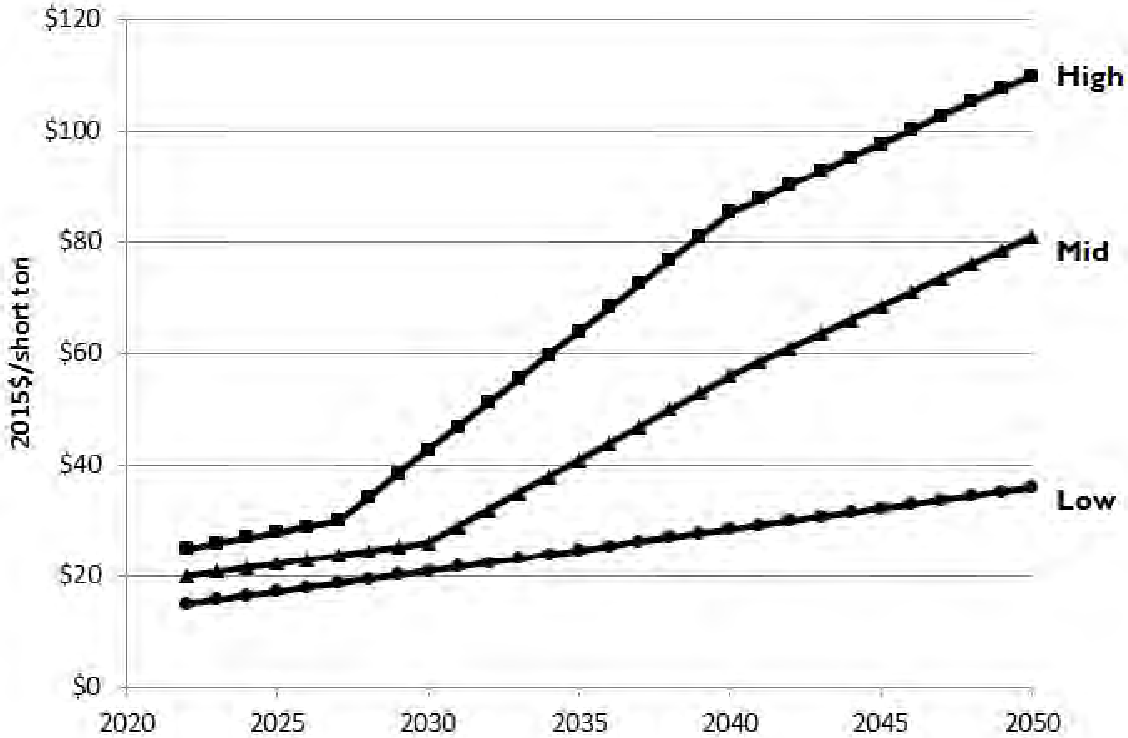
- Section 2 presents Synapse's 2016 CO_2 price forecasts.
- Section 3 discusses broader concepts of CO_2 pricing.
- Section 4 provides an overview of existing state and federal legislation, including the Environmental Protection Agency's (EPA) proposed Clean Power Plan.
- Section 5 discusses our recommendations for planning for the Clean Power Plan, a review of existing studies of compliance cost, and Synapse's modeling of compliance with the Plan.
- Section 6 provides a range of current CO_2 price forecasts used by utilities.
- Appendix A presents additional graphs comparing the 2015 forecast with past Synapse forecasts and utility forecasts.
- Appendix B presents complementary policies reducing the cost of CO_2

Unless otherwise indicated, all prices are in 2015 dollars and CO_2 emissions are given in short tons.

2. SYNAPSE 2016 CO_2 PRICE FORECASTS

Based on the evidence discussed in this report, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2022 to 2050. These forecasts reflect our best understanding of Clean Power Plan compliance costs, as well as future expected costs to meet science-based emissions targets. We believe it is highly likely that neighboring states with large disparities in mitigation costs will work together to their mutual benefit to reduce overall compliance costs. EPA has indicated it is open to such cooperation. As a result, we provide a single national-level CO_2 price and do not attempt to provide state-level forecasts. Figure 1 and Table 1 present Synapse's forecasts over the 2022-2050 period.[3]

Figure 1: Synapse 2016 CO_2 national price forecasts



Source: Synapse Energy Economics, Inc. 2016.

[3] Figure 12 compares Synapse's 2016 and 2015 CO_2 price forecasts. These forecasts do not differ substantially. Two key differences are a tighter range of prices in 2020 resulting from greater policy certainty, and higher 2015 forecasts for the Mid and High cases, resulting from the indicated stringency of the Clean Power Plan. The 2015 forecast was the first Synapse forecast to extend to 2050.

Table 1: Synapse 2016 CO_2 price forecasts (2015 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$0.00	$0.00	$0.00
2021	$0.00	$0.00	$0.00
2022	$15.00	$20.00	$25.00
2023	$15.75	$20.75	$26.00
2024	$16.50	$21.50	$27.00
2025	$17.25	$22.25	$28.00
2026	$18.00	$23.00	$29.00
2027	$18.75	$23.75	$30.00
2028	$19.50	$24.50	$34.25
2029	$20.25	$25.25	$38.50
2030	$21.00	$26.00	$42.75
2031	$21.75	$29.00	$47.00
2032	$22.50	$32.00	$51.25
2033	$23.25	$35.00	$55.50
2034	$24.00	$38.00	$59.75
2035	$24.75	$41.00	$64.00
2036	$25.50	$44.00	$68.25
2037	$26.25	$47.00	$72.50
2038	$27.00	$50.00	$76.75
2039	$27.75	$53.00	$81.00
2040	$28.50	$56.00	$85.25
2041	$29.25	$58.50	$87.75
2042	$30.00	$61.00	$90.25
2043	$30.75	$63.50	$92.75
2044	$31.50	$66.00	$95.25
2045	$32.25	$68.50	$97.75
2046	$33.00	$71.00	$100.25
2047	$33.75	$73.50	$102.75
2048	$34.50	$76.00	$105.25
2049	$35.25	$78.50	$107.75
2050	$36.00	$81.00	$110.00
Levelized 2022-2050	$23.02	$38.13	$55.27

Note: Levelized price based on a discount rate of 5 percent.

Based on analyses of the sources described in this report, and relying on our own judgment and experience, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2022 to 2050. In these forecasts, the Clean Power Plan together with other existing and proposed federal regulatory measures place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. In any state other than the

RGGI region and California, we assume a zero carbon price through 2019. Beginning in 2022, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. We assume smooth allowance trading among large groups of states. The Clean Power Plan is followed later by a more stringent federal policy in the Mid and High cases. The CO_2 prices presented here are forecasts of "effective" prices of CO_2 which may or may not take the form of market-based allowances (see Section 3 for a discussion of different types of CO_2 prices).

- The **Low case** forecasts a CO_2 price that begins in 2022 at $15 per ton.[4] It increases to $21 in 2030 and $36 in 2050, representing a $23 per ton levelized price over the period 2022-2050. This forecast represents a scenario in which Clean Power Plan compliance is relatively easy, and a similar level of stringency is assumed after 2030. Low case prices are also representative of the incremental cost to produce electricity with natural gas as compared to coal, as indicated in the Energy Information Administration's 2015 Annual Energy Outlook.

- The **Mid case** forecasts a CO_2 price that begins in 2020 at $20 per ton. It increases to $26 in 2030 and $81 in 2050, representing a $38 per ton levelized price over the period 2022-2050. This forecast represents a scenario in which federal policies are implemented with challenging but reasonably achievable goals. Clean Power Plan compliance is achieved and science-based climate targets mandate at least an 80 percent reduction in electric section emissions from 2005 levels by 2050.

- The **High case** forecasts a CO_2 price that begins in 2022 at $25 per ton. It increases to approximately $43 in 2030 and $110 in 2050, representing a $55 per ton levelized price over the period 2022-2050. This forecast is consistent with a stringent level of Clean Power Plan targets that recognizes that achieving science-based emissions goals by 2050 will be difficult. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2027. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector. Other factors that may increase the cost of achieving emissions goals include: greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

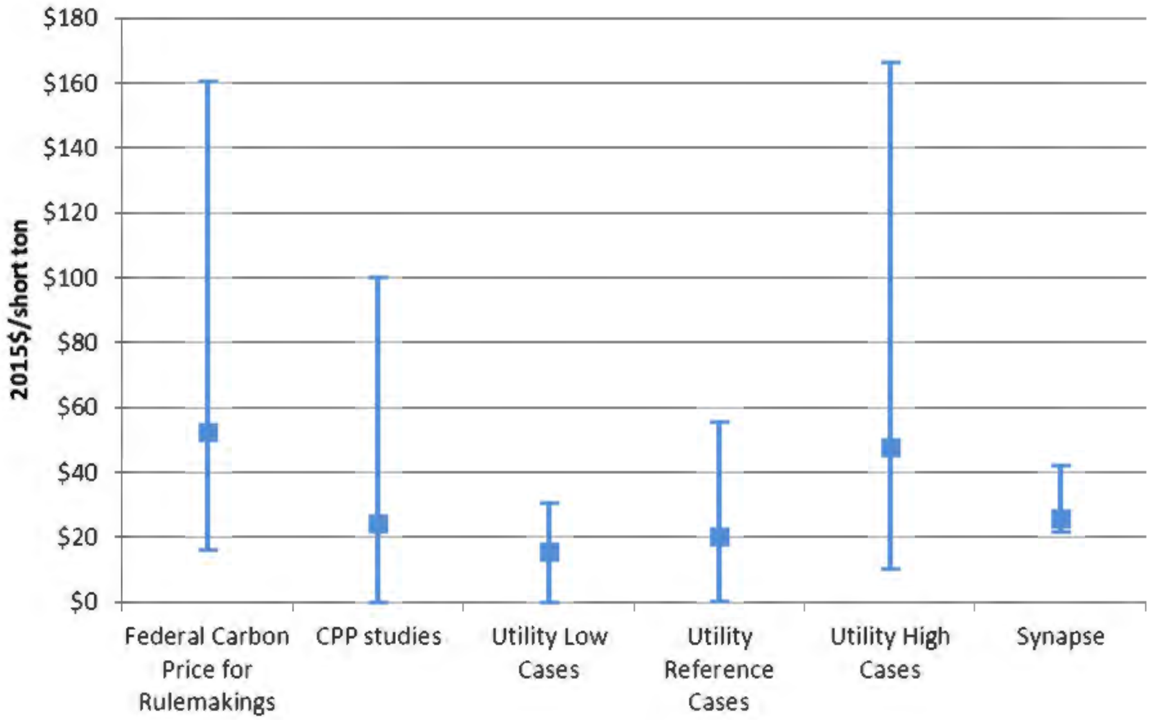
Synapse' price forecasts are presented for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price incurred by utilities in all states to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 2, the Synapse forecasts are compared to a summary of the other evidence presented in this report, including the federal CO_2 price for rulemakings; existing Clean Power Plan studies; and utility reference, low , and high scenarios (see Section 4 through 6 for a discussion of these studies). In

[4] "Tons" refer to short tons throughout this report.

addition, Synapse 2016 forecasts are also compared to the reference case utility forecasts, the Synapse 2015 forecasts in Appendix A.

Figure 2: Synapse 2016 CO_2 forecasts for 2030 compared to other sources



Source: Synapse Energy Economics, Inc. 2016.

3. WHAT IS A CARBON PRICE?

There are several meanings for the term "carbon price" or "CO_2 price," each of which is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the "price of carbon"—is ambiguous because it can at times mean several of the following.)

Carbon allowances: Sometimes called credits or certificates, carbon allowances are best known for their use in policies called "cap-and-trade." Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of CO_2 allowances are issued by a government and then sold or given away. Regardless of whether allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder. If sold at auction, allowance revenues represent a new source of revenues for public uses and may fund energy efficiency and renewable energy programs (as is the case with most revenues from RGGI). They may also be used to defray existing taxes or be rebated to electric consumers. If, instead, these allowances are given away to polluting power generators, these same revenues are a windfall to private interests.

Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business. This gives an advantage to firms with cleaner, greener operations and also creates an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the "cap" in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater emission reduction goal results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called "internalizing an externality." The external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Clean Power Plan's mass-based compliance pathways include an option for states to create markets for the purchase and sale of emission allowances denominated in tons of CO_2. The Northeast's RGGI and California's AB 32 Cap-and-Trade Program are both CO_2 allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins federal climate bills all proposed policy measures that included CO_2 allowance trading. While closely related to the various price instruments described here, the Clean Power Plan's rate-based "Emission Rate Credits" are denominated in megawatt-hours and, therefore, do not constitute a type of carbon price.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of CO_2 that they emit. If the value of damages were known with certainty, a tax could internalize the damages accurately by setting the tax rate equal to the damages; in practice, the value of damages is uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no "cap"). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a common aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

Effective price of carbon: Sometimes called a shadow, notional, hypothetical, or voluntary price, the effective price of carbon results from non-market policies. Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive *per se*, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called "command and control." For any such non-market policy there is an "effective" price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required integrated resource planning (IRP) and internal planning purposes. EPA's proposed CO_2 pollution standard for new sources of electric generation under Section 111(b) of the Clean Air Act is a non-market-based policy that would result in an effective price of carbon; similarly, the Clean Power Plan's "state measures" pathways for compliance are also fundamentally non-market policies that result in an imputed cost of mitigation.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a "supply curve" in which all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Next, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is achieved, and then asks: What would it cost to reduce emissions by the last unit needed to achieve the target? The answer is the "marginal" cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

Note that many policy analyses estimate the net costs (or benefits), comparing the total benefits of a policy to its total costs. The average cost of a policy is its net cost divided by its expected tons of emissions abated. This value is fundamentally different than the marginal cost of compliance, which is the cost to reduce the last ton of emissions (i.e., the most expensive ton actually abated). For example, a policy may result in total net benefits, but require reductions through a trading mechanism wherein the market price is set by the marginal cost of emissions. In this case, the net average policy cost is negative (a net benefit), but the marginal cost of abatement is positive (a cost for the most expensive units of emission reduction needed to achieve the goal).

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information.[5] ExxonMobil recently updated their marginal abatement cost curve in its 2016 Energy Outlook.[6]

Social cost of carbon: The marginal abatement cost estimates the price of stopping pollution. In contrast, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change resulting from the emission of one additional unit of CO_2. Estimating the uncertain costs of uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is intended to be an estimate of the social cost of carbon.[7]

4. STATE AND FEDERAL CO_2 POLICIES

In October 2015, the United States Environmental Protection Agency (EPA) released the final version of the Clean Power Plan under Section 111(d) of the Clean Air Act, aiming to reduce emissions from existing power pants. At the same time, EPA released New Source Performance Standards for new power plants. These federal regulations are in addition to a suite of complementary policies impacting emitting resources, including standards on regional haze, mercury, and coal waste. Many states had

[5] Wilson et al. 2012. *2012 Carbon Dioxide Price Forecast.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

[6] ExxonMobil. 2016. "The Outlook for Energy: A view to 2040." Available at: http://corporate.exxonmobil.com/en/energy/energy-outlook/charts-2016/united-states-c02-abatement-costs.

[7] U.S. EPA. 2015. *EPA Fact Sheet: Social Cost of Carbon.* Available at http://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

their own emissions goals and standards in advance of these regulations. In its 2016 "Outlook for Energy", ExxonMobil assumes such state and federal policies will result in an effective price of $73 per short ton by 2040.[8]

4.1. Clean Air Act CO_2 Regulations

As part of the Administration's Climate Action Plan, which aims to significantly reduce greenhouse gas emissions from all sectors of the U.S. economy, President Obama directed EPA to issue emission standards for new and existing fossil fuel-fired electricity generators using its authority under the Federal Clean Air Act.

New Source Performance Standards

In October 2015, EPA released final New Source Performance Standards aimed at reducing CO_2 from new, modified, and reconstructed fossil fuel power plants under Section 111(b) of the federal Clean Air Act. These New Source Performance Standards are based on EPA's assessment of available technologies and they establish emission performance standards using the maximum allowable emissions of CO_2 per unit of electricity generated (i.e., lbs CO_2 per MWh) for all fossil fuel power plants on which construction commenced after January 8, 2014. The final standards were set at 1,400 lbs CO_2 per MWh for new coal-fired power plants and 1,000 lbs CO_2 per MWh for new, baseload gas-fired plants.

The standards for modified and reconstructed coal and gas units were finalized at the same time. These are existing coal or gas resources that undergo physical or operational changes that increase the maximum hourly CO_2 emissions rate (for modified resources) or that replace components to such an extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable facility (for reconstructed resources). Coal plant modifications that result in an increase of hourly CO_2 emissions of more than 10 percent will be required to meet an emission rate limit consistent with that plant's best historical annual performance since 2002.

Reconstructed coal plants would be required to meet an emission limit of 1,800 lbs CO_2 per MWh.[9] Reconstructed gas plants must meet the same emission limits as new gas plants, while EPA deferred a decision on limits for modified gas plants until it can gather additional information.

Existing Sources under the Clean Power Plan

In October 2015, EPA also released its Clean Power Plan aimed at existing sources. Under the Clean Power Plan, the electric sector—which is the single largest producer of greenhouse gases—is expected

[8] ExxonMobil. "The Outlook for Energy: A view to 2040." January 2016. Available at: http://corporate.exxonmobil.com/en/energy/energy-outlook/download-the-report/download-the-outlook-for-energy-reports

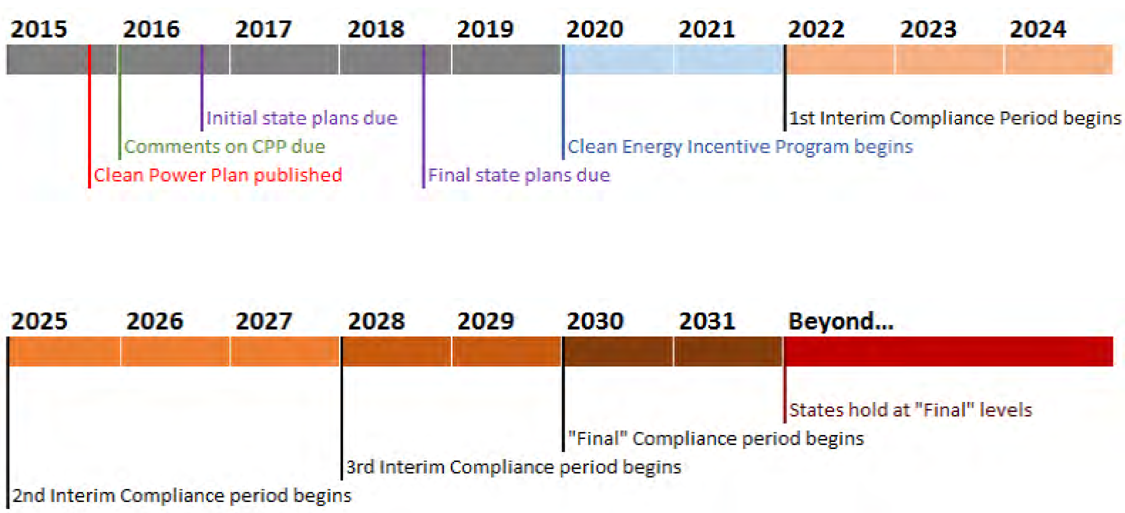
[9] Smaller coal plants (those with a heat input of less than 2,000 MMBtu per hour) would be required to meet an emission limit of 2,000 lbs CO_2 per MWh.

to reduce CO_2 emissions from 2005 levels by about 32 percent nationwide by 2030. To reduce CO_2 emissions from existing power plants, EPA established emission performance standards for two electric generating technology types—fossil steam (mainly coal and some oil) and stationary combustion turbines (mainly natural gas combined-cycle, or NGCC, plants)—based on the degree of emission reductions achievable through what is called the "best system of emission reduction" or BSER. BSER includes not only upgrades and operational changes to power plants, but also measures such as increased renewable energy and shifting generation from higher-emitting resources to lower-emitting resources. An example of the latter would be a shift in generation from coal-fired plants to natural gas plants. For a detailed discussion of the Clean Power Plan targets and compliance options see the Synapse 2015 *Clean Power Plan Handbook.*[10]

States may choose among different manners of complying with the rule: they can comply using either a rate-based or a mass-based approach; they can include just existing sources, or both existing and new sources; and they can use targets based on technology type (i.e., fossil steam versus NGCC) or state averages.

States must now develop compliance plans to submit to EPA. Initial draft compliance plans or requests for extension with demonstrations of progress are due September 6, 2016, and final plans are due no later than September 6, 2018 (see Figure 3). During plan development, states may follow the approaches outlined by EPA during target setting, or they may design their own strategies to comply with the targets.

Figure 3. Clean Power Plan compliance timeline



[10] Jackson et al. 2015. "Clean Power Plan Handbook: A Guide to the Final Rule for Consumer Advocates." Prepared by Synapse Energy Economics for the National Association of State Utility Consumer Advocates. Available at: http://www.synapse-energy.com/sites/default/files/Clean-Power-Plan-Handbook.pdf.

Source: Synapse Energy Economics, Inc. 2016.

In their plans states must demonstrate that their compliance strategy achieves an emission rate (lbs/MWh) or mass (tons) equal to or better than the targets set by EPA for the three interim compliance periods (2022-2024, 2025-2027, and 2028-2029), a final compliance period (2030-2031), and biennially thereafter. Depending on the compliance approach a state chooses, these demonstrations may be more or less complex.

Throughout the rule, EPA emphasizes regional cooperation and coordinated planning as one of the best approaches for compliance. The agency provides extensive guidance on the development and use of emission trading programs, and states that the larger the region over which trading occurs, the more effective—and cost-effective—compliance will be. To date, there are several emission trading programs that exist in the United States and abroad, including RGGI in the Northeast and California's AB 32 Cap-and-trade program. These existing programs take a mass-based approach to trading in which CO_2 allowances representing the ability to emit one ton of CO_2 are traded with eligible partners throughout a defined region.

States that choose a mass-based compliance approach can establish trading programs in which electricity generators have the opportunity to trade allowances. One allowance represents one short ton of CO_2. Every generator subject to the Clean Power Plan must procure allowances equal to the quantity of CO_2 it emits during the compliance period. The total number of allowances that are distributed in a state, i.e., the state's emission budget, is equal to the state's mass-based goal.

Existing mass-based trading programs, including RGGI in the Northeast, use an auction process to distribute some or all allowances. Auctions have many potential benefits, including providing incentive for early action, avoiding indirect subsidies that can prolong operation of uneconomic resources, and lowering policy and consumer costs through revenue recycling.

States that choose a rate-based approach to compliance—which may include those with large new nuclear units expected to come online before the first Clean Power Plan compliance period (South Carolina, Tennessee, and Georgia)—might require a separate effective CO_2 price forecast.

4.2. Complementary Federal Policies

In addition to the Clean Power Plan and New Source Performance Standards for CO_2 emission reductions, there are a number of federal environmental regulations that limit or add costs to fossil fuel-powered electric generation. By doing so, they indirectly lead to an effective price of CO_2. These complementary policies are summarized in Table 2 and described in detail in Appendix B. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometimes rendering them uneconomic—causing a reduction in generation from these facilities or even leading to their retirement. Federal regulation of pollutants from power plants are evidence of momentum towards more stringent control of environmentally harmful activities in the electric sector. To the extent that electric generators with high emissions of non-CO_2 pollutants also have high CO_2 emissions, these policies represent an effective price on CO_2 that would *lower* the incremental CO_2 price necessary to achieve a given system-wide emission reduction; as more pollution-intensive plants retire in response to other EPA regulations, the incremental CO_2 price necessary to achieve science-based climate goals is reduced. Synapse's CO_2 forecast is the incremental effective CO_2 price over and above the impacts of non-CO_2-related policies.

Table 2: Summary of power sector environmental regulations that may result in reduced greenhouse gas emissions

Rule	Current Status as of Release	Next Deadline(s)	Pollutants Covered
Federal Regulations			
Clean Air Act, Section 111	New Source Performance Standards for GHGs from new sources under 111(b) was finalized on August 3, 2015	Applies to sources that begin construction on or after January 8, 2014	CO_2 and other greenhouse gases
	New Source Performance Standards for GHGs from modified or reconstructed sources under 111(b) was finalized on August 3, 2015	Applies to sources that were modified or reconstructed after June 28, 2014	
	Clean Power Plan for reducing CO_2 from existing sources under 111(d) was finalized in October 2015	States must submit compliance plans or initial plan and request for extension to EPA by September 6, 2016	
National Ambient Air Quality Standards (NAAQS)	1-Hour SO_2 NAAQS was finalized in June 2010; next 5-year review underway	Initial designations were made in June 2013; additional designations for major emitters required by July 2, 2016 per consent decree	Sulfur dioxide; nitrogen oxides; carbon monoxide; ozone; particulate matter; and lead
	PM2.5 annual NAAQS was finalized in December 2012	Final designations announced December 18, 2014; SIPs due in April 2018 with attainment required by 2020	
	8-Hour Ozone NAAQS was finalized in October 2015	Designations for updated standard will be made in late 2017; attainment dates vary by severity of problem	
Cross State Air Pollution Rule (CSAPR)	U.S. Supreme Court reinstated CSAPR in April 2014, finding that EPA had not exceeded its authority in crafting the rule	Court lifted stay of CSAPR on October 23, 2014; on November 21, 2014, EPA published rules pushing back CSAPR deadlines three years – Phase I began January 1, 2015 and Phase II begins January 1, 2017	Nitrogen oxides and sulfur dioxide
Mercury and Air Toxics Standards (MATS)	Finalized in December 2011; remanded by U.S. Supreme Court in July 2015 for failing to consider costs; in December 2015, D.C. Circuit rejects request to vacate rule, leaving it in place while EPA develops cost assessment	Compliance required by April 16, 2015; rule allows for a 1-year extension if certain conditions are met	Mercury, metal toxins, organic and inorganic hazardous air pollutants, and acid gases
Coal Combustion Residuals (CCR) Disposal Rule	EPA issued final rule regulating CCR on December 19, 2014	Effective October 19, 2015; utilities must file intent to close legacy ash ponds by December 17, 2015; structural safety inspections due October 2016	Coal combustion residuals (ash)
Steam Electric Effluent Guidelines (ELGs)	EPA issued final rule on September 30, 2015	Pretreatment requirements by November 2018; Best Available Technology requirements phased in over 5-year NPDES permitting cycle	Toxins and wastewater entering waterways
Cooling Water Intake Structure (316(b)) Rule	EPA released a final rule for implementation of Section 316(b) of the Clean Water Act on May 19, 2014	Final rule became effective October 14, 2014 and requirements will be implemented in NPDES permits as they are renewed	Cooling water intake
Regional Haze Rule	Regional Haze Rule issued in July 1999	States must install the Best Available Retrofit Technology (BART) controls on eligible units by 2018; thereafter, states must demonstrate "reasonable progress" toward natural conditions by 2064	Sulfur oxides, nitrogen oxides, and particulate matter

4.3. State and Regional Policies

State and regional environmental policies regulating power plants can also result in an effective CO_2 price. Currently, 29 states have renewable portfolio standards and 26 have efficiency standards. Twenty states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[11][12] In addition, there are two regional and state cap-and-trade programs in the United States today: the Northeast's RGGI and California's Cap-and-Trade Program under the state's Global Warming Solutions Act (Assembly Bill 32).

Regional Greenhouse Gas Initiative

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. RGGI has had more than seven years of successful CO_2 allowance auctions, with Auction 30 in December 2015 resulting in a clearing price of $7.50 per ton.[13] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[14]

RGGI is also a potential avenue for Clean Power Plan compliance for these states.

While the RGGI targets are largely consistent with (and slightly more stringent than) the states' Clean Power Plan targets, a recent Pace Energy and Climate Center analysis showed that the availability and use of cost containment reserves—which limit increases in the allowances prices by automatically loosening CO_2 limits—could keep the RGGI states from meeting their federal targets. Without use of the cost containment reserve instrument, allowance prices are likely to increase.

California's AB 32 Cap-and-Trade-Program

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB 32) created the world's second largest carbon market, after the European Union's Emissions Trading System.

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[11] NC Clean Energy Technology Center. *Database of State Incentives for Renewables & Efficiency (DSIRE).* DSIRE Detailed Summary Maps: Renewable Portfolio Standards and Energy Efficiency Resource Standards. Accessed: Jan 19, 2016. Available at: http://www.dsireusa.org/resources/detailed-summary-maps/.

[12] Center for Climate and Energy Solutions. "Greenhouse Gas Emissions Targets." *U.S. Climate Policy Maps.* Accessed Jan 19, 2015. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[13] Regional Greenhouse Gas Initiative (RGGI). RGGI Auction 23 results available at: http://rggi.org/market/co2_auctions/results/Auction-23.

[14] RGGI. 2013. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." Press Release. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

On January 1, 2014, California and Québec formally linked their carbon markets. The first joint auction was held in November 2014 and cleared at $10.98 per short ton.[15] The second joint auction was held on February 18, 2015, and cleared at $11.08. This auction, which was the first to include transportation fuels, sold 73.6 million allowances, as compared to only 23 million allowances in the prior November 2014 auction.[16] In 2015, Ontario and Manitoba announced that they would soon join California and Québec in a unified cap-and-trade system.[17]

While the current cap-and-trade program in California only runs through 2020, the passage of Senate Bill 350 in 2015 increased the states renewable portfolio standard goals to 50 percent by 2030 and doubled building efficiency standards.[18] Also in 2015, Governor Jerry Brown set new goal of 40 percent below 1990 levels of statewide greenhouse gas emissions by 2030, by executive order. The legislature will still need to approve the legal framework for expansion of the cap-and-trade system in this timeframe.

Historical RGGI and California auction prices are presented in Figure 4 below.

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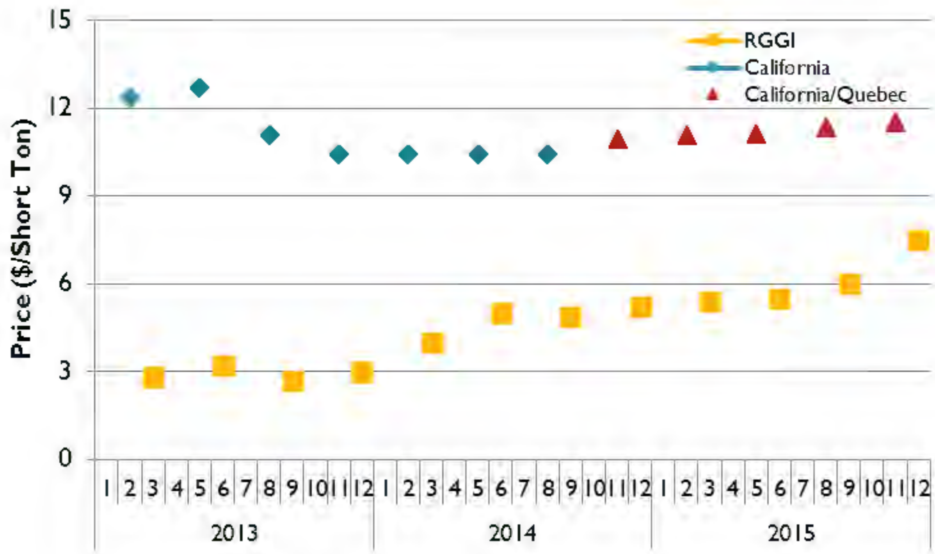
15 California Air Resources Board. 2015. California Cap and Trade Program Summary of Auction Results. Updated 1/12/2015. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

16 California Air Resources Board. 2015. *California Cap and Trade Program and Quebec Cap and Trade System February 2015 Joint Auction #2 Summary Results Report*. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/feb-2015/summary_results_report.pdf.
Auctions clear in dollars per metric tons – values here have been converted to short tons.

17 Hamilton, T. 2015. "Ontario agrees to linked cap-and-trade deal with Quebec, Manitoba." *The Star*. December 7. Available at: http://www.thestar.com/news/canada/2015/12/07/manitoba-sign-paris-deal-to-join-ontario-quebec-in-carbon-cap-and-trade-system.html.

18 Environmental Defense Fund. 2015. "California Makes Clean Energy History with Passage of SB 350." Blog published September 14 at: http://blogs.edf.org/energyexchange/2015/09/14/california-makes-clean-energy-history-with-passage-of-sb-350/.

Figure 4: Auction results from RGGI and California cap-and-trade programs



Source: RGGI Auction Results available at: https://www.rggi.org/market/co2_auctions/results. California Air Resources Board Summary Results available at: http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

4.4. CO_2 Price for Federal Rulemaking

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[19] updated values were released in 2013.[20] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[21]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, Department of Transportation, and Office of Management and Budget, among others—was tasked with developing a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 1 for more explanation of the "social cost of carbon" methodology). These

[19] Interagency Working Group on the Social Cost of Carbon, U. S. G. 2010. "Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866." In *Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors*. U.S. Department of Energy. Available at: http://go.usa.gov/3fH.

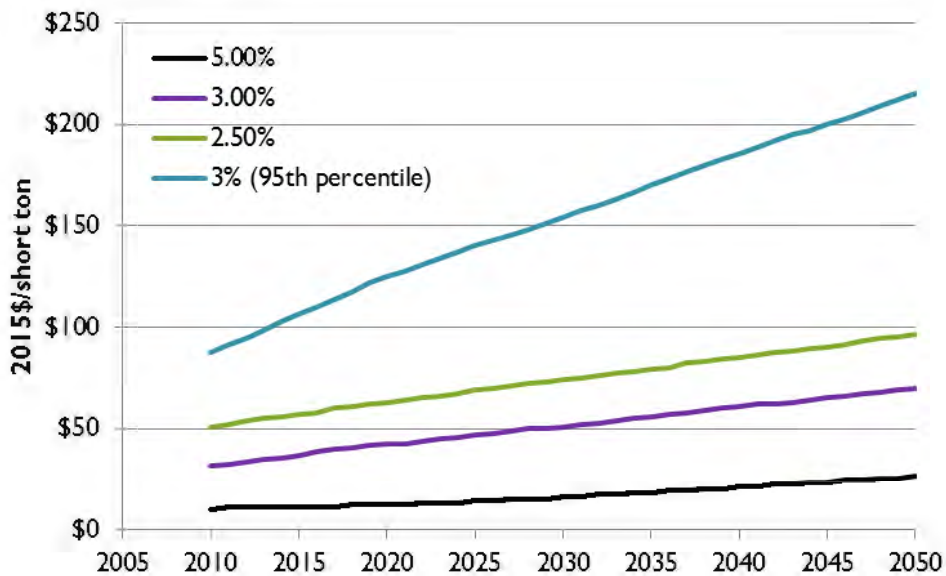
[20] Interagency Working Group on the Social Cost of Carbon. 2013. *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866*. Available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. Reported values have been converted to 2015 dollars per short ton.

[21] The White House. 2013."Climate Change and the Path Toward Sustainable Energy Sources." *2013 Economic Report of the President*. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

values—$11, $36, $57, and $103 per short ton of CO_2 in 2013, and rising over time—represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[22] While subject to significant uncertainty, this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy. These values are presented in Figure 5.

The average social cost of CO_2 at a 3 percent discount rate—$36 in 2015—is often called the "central value" by EPA and is commonly used in federal rulemakings to represent the value of CO_2 emissions avoided by the policy under consideration. While a CO_2 price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government and may therefore impact on the effective price of CO_2.

Figure 5: Range of federal social cost of CO_2 estimates, by discount rate



Source: Synapse Energy Economics, Inc. 2016.

[22] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate. They found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater [Frank Ackerman and Elizabeth A. Stanton. 2012. "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10]. Similarly, Laurie Johnson and Chris Hope modified discount rates and methodologies and found results up to 12 times larger than the Working Group's central estimate [Laurie T. Johnson, Chris Hope. 2012. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*; DOI: 10.1007/s13412-012-0087-7].

4.5. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by more than 80 percent below recent levels by 2050. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in 2009: the American Clean Energy and Security Act, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in the 2009-2010 session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[23] Further analysis of these proposals is provided in Synapse's *2012 Carbon Dioxide Price Forecast*.[24]

We expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. The Clean Power Plan represents an effective price of greenhouse gas emissions, but is not expected to meet long-term science-based goals of reducing total U.S. greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050.[25] A more comprehensive, economy-wide approach will be needed to meet these goals at the lowest possible cost to consumers.

5. THE COST OF IMPLEMENTING EPA'S CLEAN POWER PLAN

With EPA's Clean Power Plan finalized in October, states have just begun the process of modeling compliance options, drafting state implementation plans, and analyzing the potential costs associated with achieving compliance. In addition to EPA's estimates of the costs of compliance using ICF's Integrated Planning Model (IPM) model, many other researchers have estimated the cost of the Clean Power Plan at state, regional, and national levels, as summarized in Figure 6.[26]

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[23] U.S. Energy Information Administration (EIA). 2010. "Energy Market and Economic Impacts of the American Power Act of 2010." Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html.

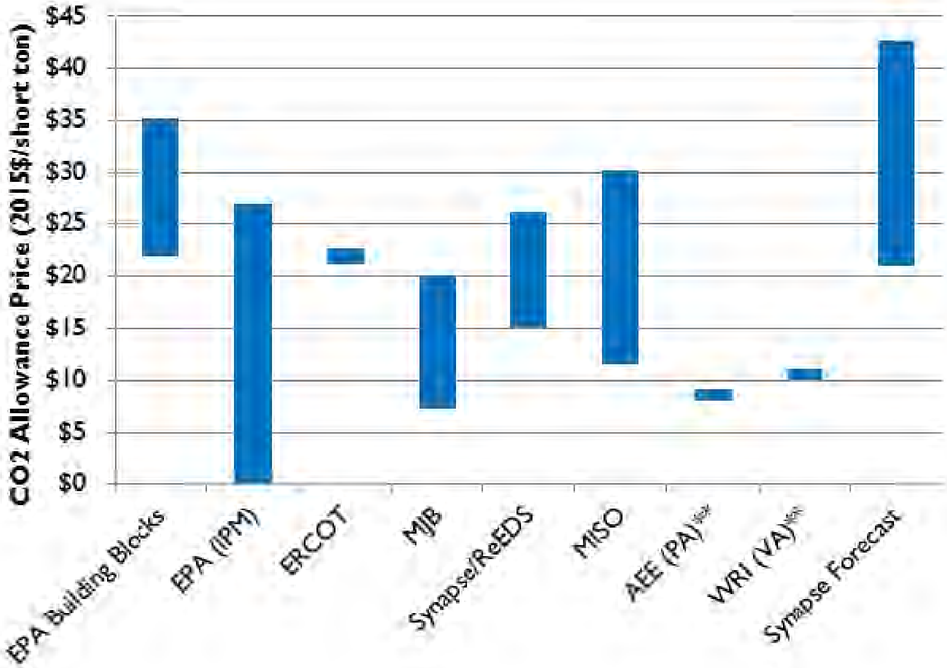
EIA. 2009. "Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009." Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[24] Wilson et al. 2012.

[25] World Resource Institute. 2013. "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Report available at: http://www.wri.org/publication/can-us-get-there-here.

[26] Three studies, MISO, AEE, and WRI, assumed an exogenous price. This should be interpreted differently than the more analytically determined prices from the other studies.

Figure 6: Summary of Clean Power Plan study CO_2 price estimates for 2030 (2015 dollars/short ton)



Source: Synapse Energy Economics, Inc. 2016.

Synapse's nationwide allowance price falls within the range of other publicly available findings. Studies' CO_2 prices associated with compliance depend on a number of factors, including assumptions about cooperation, fuel prices, renewable and energy efficiency costs, and retirements.

5.1. EPA's IPM Results

In the final Clean Power Plan rule, EPA provides a range of estimates of the modeled cost of compliance with the final rule based on the two main target options. Compared to a non-compliant base case, EPA estimates annual Clean Power Plan costs growing steadily to $8.4 billion nationwide in 2030 under a rate-based approach to compliance, and to $5.1 billion under a mass-based approach to compliance.[27] These costs are incremental to the base case, and represent a combination of electric generating production cost savings plus the costs of demand side resources and measurement and verification of results. To put these costs in perspective to the CO_2 prices forecasted in this report, EPA found that the

[27] U.S. EPA. 2015. *Regulatory Impact Analysis for the Clean Power Plan Final Rule*. Table ES-5. Revised: October 23. Available at: http://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf. *Note: EPA's cost estimates are in 2011 dollars.*

range of CO_2 prices necessary for Clean Power Plan compliance ranged from $0 per short ton—in states without much work to do to comply— to $26/short ton in coal heavy states.[28]

This analysis is separate from EPA's "building block" analysis in the final rule. Here it estimated the cost of emissions reductions from the three building blocks: operational improvements at existing coal plants, shifting generation from coal power plants to gas power plants, and increasing generation from renewable energy. They found these measures to cost $23 per ton, $23 per ton, and $37 per ton, respectively, with a weighted average of $30 per ton.[29]

5.2. ERCOT's Texas Results

Electric Reliability Council of Texas (ERCOT) analyzed three different paths to compliance for the state of Texas: an energy efficiency scenario with a modest level of savings (7 percent cumulative savings by 2030), a simple CO_2 price optimization, and a combination of increased coal retirements from the Regional Haze rule and a CO_2 price optimization.[30] The two scenarios explicitly incorporating a CO_2 price found that the price would rise from $1/short ton in 2022 to $22.50/short ton in 2030, or from $0/short ton in 2022 to $21.50/short ton in 2030 as a result of additional retirements in the Regional Haze case. In the energy efficiency scenario, the cost of energy rises 11 percent above a non-compliant base case, while it rises 20 to 44 percent above the base case in the CO_2 scenarios. This implies a shadow price of CO_2 in the energy efficiency case much lower than that observed in the cases explicitly modeling a CO_2 price.

5.3. MISO's Midwest Results

MISO used the PLEXOS production cost model to update its draft analysis for the final rule. This analysis found that—without building any new capacity—mass-based compliance could be achieved at a cost of $5 billion for the full MISO system, while rate-based compliance cost $17 billion. New natural gas power

[28] U.S. EPA. "Analysis of the Clean Power Plan." Last accessed January 28, 2016. Available at: http://www.epa.gov/airmarkets/analysis-clean-power-plan.

[29] Final Rulemaking, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Federal Register/ Vol. 80, NO. 205. October 23, 2015 Page 64749. Available at: https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf.

[30] Electric Reliability Council of Texas. 2015. *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update*. Available at: http://www.ercot.com/content/news/presentations/2015/ERCOT_Analysis_of_the_Impacts_of_the_Clean_Power_Plan-Final_.pdf.

plants, renewable energy facilities, or energy efficiency would reduce this cost. These capacity additions reduced the marginal CO_2 price in 2030 from $30 per short ton to $11 per short ton.[31]

5.4. M.J. Bradley Analysis

M.J. Bradley & Associates (MJB) used the same model EPA used in their analysis of the Clean Power Plan, IPM, to analyze compliance costs under a much broader range of sensitivities, assuming varying levels of energy efficiency and interstate trading under mass-based and rate-based policies.[32] MJB found that coal declined to supply 23 to 28 percent of total generation under Clean Power Plan cases. Natural gas supplied 25 to 32 percent. As the level of energy efficiency increased, MJB found steady reductions in allowance prices.

This analysis considered compliance plans on "existing units only," as well as "existing plus new" scenarios that incorporated EPA's New Source Complement. Emissions under an existing unit only approach were 94 million tons higher— suggesting these plans are more susceptible to leakage.

5.5. Energy Ventures Analysis updated analysis for NMA

For the final rule, Energy Ventures Analysis (EVA) updated its 2014 analysis of the Clean Power Plan performed for the National Mining Association.[33] EVA used the AURORA dispatch model to calculate the lowest cost compliance pathway, assuming no interstate trading (similar to the EPA modeling). While EVA did not present the resulting allowance prices from their analysis, wholesale electricity prices rose 10 percent in 2022 and 21 percent by 2030. This contributed to a total wholesale electricity spending increase of $15 billion in 2022, and $32 billion in 2030. These values are substantially higher than EPA's ($8.4 billion total costs in 2030), and do not include incremental capital spending.

5.6. NERA Consulting Report on Final Rule

NERA used its energy and economy model, NewERA, to analyze the impacts of the Clean Power Plan under two mass-based scenarios: one with no trading and one with regional trading.[34] While NERA did

[31] Midcontinent Independent System Operator (MISO). 2016. "Results for MISO's Near-Term Analysis of EPA's Final Clean Power Plan." Last accessed January 20th 2016. Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2016/20160120/20160120%20PAC%20Item%2002aii%20CPP%20Final%20Rule%20Analysis%20Near%20Term%20Results.pdf.

[32] M.J. Bradley & Associates. 2016. "Modeling Analysis of EPA's Clean Power Plan." Available at: http://www.mjbradley.com/reports/modeling-analysis-epas-clean-power-plan.

[33] Energy Ventures Analysis. 2015. "EPA's Clean Power Plan: An Economic Analysis." Available at: http://nma.org/attachments/article/2368/11.13.15%20NMA_EPAs%20Clean%20Power%20Plan%20%20An%20Economic%20Impact%20Analysis.pdf.

[34] National Economic Research Associates. 2015. "Energy and Consumer Impacts of the EPA's Clean Power Plan." Available at: http://www.americaspower.org/nera/.

not report allowance prices from these case. The case with no trading had a cumulative impact of $241 billion dollars, in present value terms. With trading, the cost was reduced to $220 billion, an 8 percent decrease.

5.7. AEE's Pennsylvania Results

Advanced Energy Economy (AEE) conducted an analysis of Clean Power Plan compliance approaches for the Commonwealth of Pennsylvania. In this analysis Pennsylvania achieved compliance using an assumed allowance trading price of $8/short ton, with a sensitivity at $4/short ton, based on historical prices in RGGI and California markets.[35]

5.8. WRI's Virginia Results

World Resources Institute did a similar analysis for the state of Virginia and in which Clean Power Plan compliance was achieved using an assumed $10/short ton allowance price.[36]

5.9. Synapse's U.S. States Results

For this report, Synapse used the ReEDS (Regional Energy Deployment System) model, built by the National Renewable Energy Lab, to estimate expected allowance prices under two scenarios of Clean Power Plan compliance. The first assumed full trading amongst all states, and the second separated out the three major electrical interconnects. In the latter, these separate groups must comply independently and are not allowed to trade with others. Closely related Synapse analyses were recently published as *The RGGI Opportunity*[37] and *Cutting Electric Bills with the Clean Power Plan.*[38]

ReEDS selects the types of power generation to build and operate in different parts of the country with the goal of achieving the least total cost. It draws many of its assumptions from the EIA's 2015 Annual Energy Outlook. Synapse's Clean Power Plan scenarios included state caps on CO_2 emissions consistent

[35] Advanced Energy Economy. 2015. "Model Shows Clean Power Plan Could Produce Savings for Pennsylvania Ratepayers." Available at: https://www.aee.net/articles/model-shows-clean-power-plan-could-produce-savings-for-pennsylvania-ratepayers.

[36] World Resources Institute. 2015. "How Virginia Can Meet its Clean Power Plan Targets." Available at: http://www.wri.org/sites/default/files/wri15_fact_sheet_VA_Clean_Power_1.pdf.

[37] Stanton, E.A, P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. Santen, K. Takahashi. 2016. "The RGGI Opportunity." Synapse Energy Economics. Available at: http://www.synapse-energy.com/sites/default/files/The-RGGI-Opportunity.pdf.

[38] Knight, P., A. Allison, W. Ong, N. Santen, E. Stanton. 2016. "Cutting Electric Bills with the Clean Power Plan." Synapse Energy Economics. Available at: http://www.synapse-energy.com/sites/default/files/cutting-electric-bills-cpp.pdf.

with EPA's mass-based targets for existing sources with a new source complement.[39] After 2030, we assume the cap remains flat at 2030 levels. We believe this to be a very conservative assumption—continued global pressure to meet science-based emissions goals of 80 percent below 2005 levels will require even further reductions. This analysis was conducted using an in-house Synapse version of the ReEDS model, modified to include the latest known power plant additions and retirements, renewable portfolio standards, state energy efficiency standards and technology cost assumptions.[40] This analysis is based on AEO 2015 natural gas prices, which rise from $5.30 per million BTU in 2022 to $5.93 per million BTU in 2030. Importantly, this analysis used baseline levels of energy efficiency consistent with existing state standards. Further energy efficiency would reduce compliance costs. ReEDS assigns CO_2 prices by year and trading area as a shadow price necessary to achieve Clean Power Plan compliance.

The resulting allowance prices should be applicable for reasonably large groups of states that allow for trading of allowances or emissions rate credits (ERCs) among the group. For individual states that take an isolate approach to Clean Power Plan compliance, the relevant CO2 price could be significantly higher. Alternatively, if a state relatively low-cost compliance chooses to avoid trading, it could achieve a very low cost of CO_2. That state would, however, miss the benefits of selling allowances for that over-compliance.

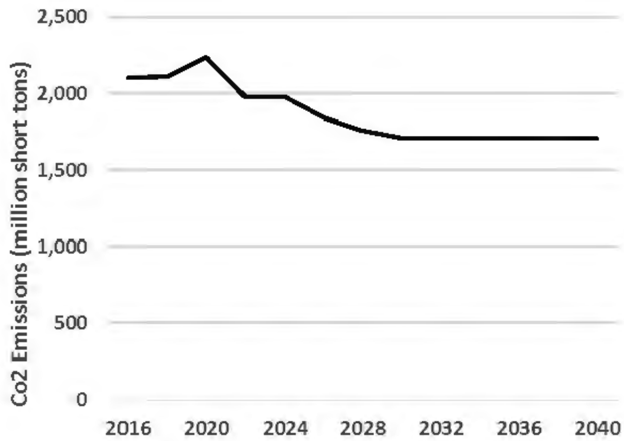
Figure 8 reports aggregate national emissions for both scenarios. Emissions slowly rise towards 2020 as gas prices increase from recent lows, leading to increased utilization of coal resources. As shown in Figure 8, when nationwide trading is permitted allowance prices typically range from $15 to $25/short ton (in 2014 dollars) throughout the 2022-2032 Clean Power Plan compliance timeframe. [41] In the regional trading scenario, prices are highest in the East, ranging from $21 to $28 per short ton in the Clean Power Plan compliance timeframe. The West sees lower costs due to both excellent renewable resource options and substantial complementary policies, such as California's recently announced 50 percent renewable portfolio standard.

[39] U.S. EPA. 2014. "Clean Power Plan Proposed Rule: Translation of State-Specific Rate-Based CO2 Goals to Mass-Based Equivalents." Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-translation-state-specific-rate-based-co2.

[40] Stanton, E.A et al. 2016. "The RGGI Opportunity."

[41] The West has a zero carbon allowance price between 2022 and 2025, largely driven by the RPS in California exceeding the Clean Power Plan requirements. These numbers would change if California were to not participate in trading.

Figure 7: National CO_2 emissions under all scenarios (million short tons)



Source: Synapse Energy Economics, Inc. 2016

Figure 8: CO_2 allowance prices with nationwide trading area ($/short ton)

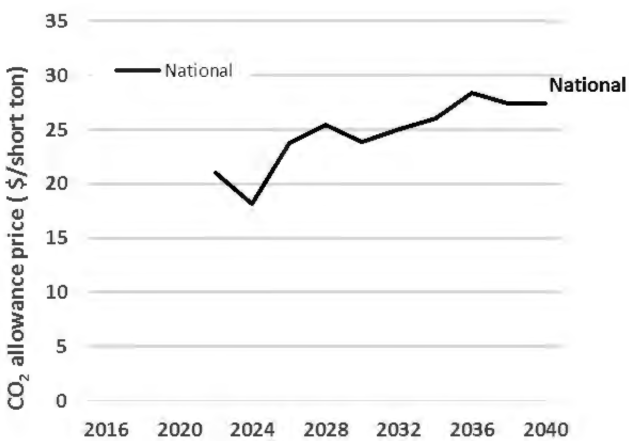
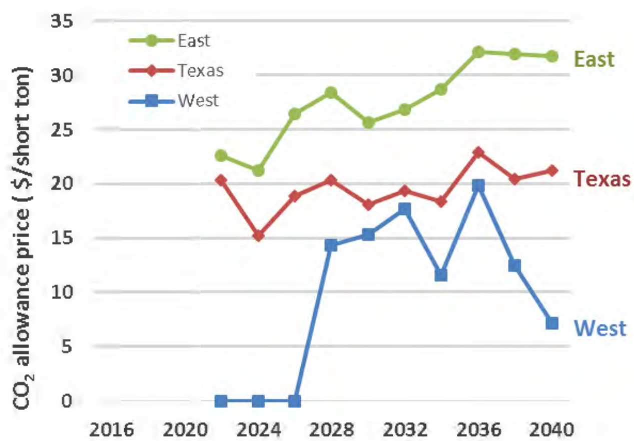


Figure 9: CO_2 allowance prices with no trading between interconnects ($/short ton)



Source: Synapse Energy Economics, Inc. 2016.

6. CO_2 Price Forecasts in Utility IRPs

Many electric utilities include projections of the expected costs associated with reductions to greenhouse gas emissions in their resource planning. In addition to the pool of recent IRPs reviewed for this forecast, which are characterized below, Synapse has previously conducted an extensive study of resource plans dating back to 2003. We have not updated this analysis since the release of our 2015 CO2 Price Forecast in May 2015. The release of the final Clean Power Plan has led some utilities to reconsider their analysis, and IRPs incorporating compliance with the Clean Power Plan are just beginning to emerge. We believe the set of utility forecasts presented here provides a reasonable reflection of the current expectation for compliance costs associated with policies of moderate stringency in the 2020-2030 timeframe, largely consistent with the Clean Power Plan.

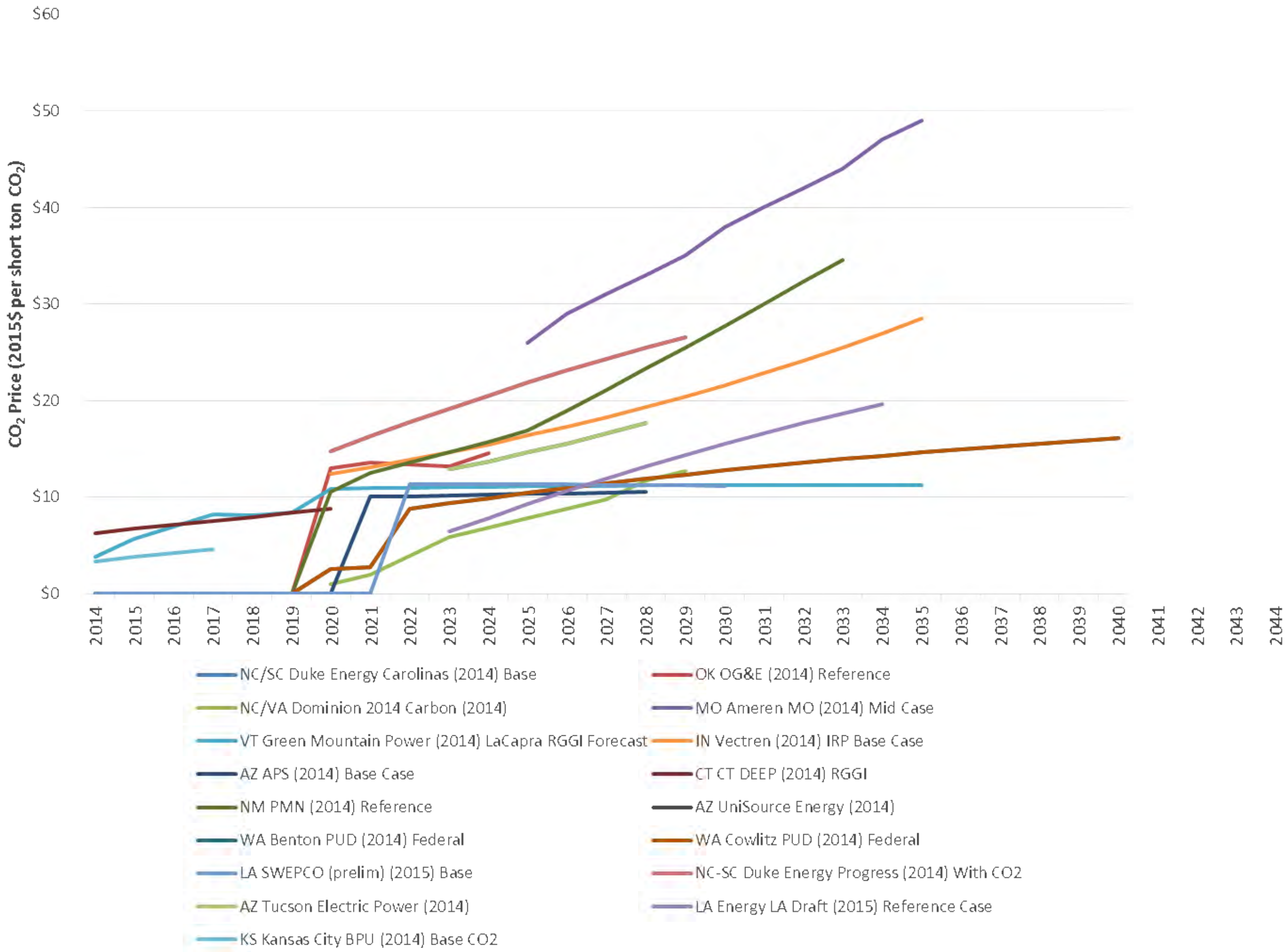
History has shown a steady increase in the number of utility planning processes that include a CO_2 price:

- None of the 15 IRPs published from 2003-2007 reviewed by Synapse included a CO_2 price forecast.
- Of the 56 IRPs from 2008-2011 reviewed, 23 included a CO_2 price forecast. This jump in the inclusion of CO_2 price projections in IRPs from 2008 onwards coincided with the introduction of the Waxman-Markey cap-and-trade bill in Congress. As a result of this bill, the inclusion of CO_2 pricing sensitivities in IRPs became paramount to prudent planning. A majority of the IRPs in our 2015 review reflect an understanding that including a price to reflect future environmental regulations is necessary to prudent planning.
- Of the 115 IRPs released in 2012-2015 and reviewed by Synapse (referred to below as the "current sample"), 66 include a CO_2 price in at least one scenario, including 61 with a CO_2 price in their reference case scenario.
- Moreover, of the 24 IRPs in the Synapse review that were released in 2014-2015, 20 included a CO_2 price in at least one scenario. Of these, 19 includes a CO_2 price in their reference case scenario.

Figure 10 below displays non-zero reference case CO_2 price forecasts from 24 utility IRPs over the period of 2014-2044.[42] Although we refer above to 61 non-zero CO_2 price reference case forecasts in the current sample, 15 of these forecasts are excluded from this chart for various reasons. In some cases, our sample includes IRPs from companies in 2012 *and* 2014, in which case we only include the most recent forecast in Figure 10. The remaining non-zero forecasts that are not included in the figure below are from companies that operate in multiple states but produce the same CO_2 forecast, are confidential, or forecast a price that begins following the end of the IRP planning period.

[42] We also provide a figure showing 46 forecasts produced since 2012 in Appendix A.

Figure 10: 2014 and 2015 utility non-zero and non-confidential reference case forecasts



Source: Synapse Energy Economics, Inc. 2016.

APPENDIX A: SYNAPSE FORECASTS COMPARED TO UTILITY FORECASTS AND PAST SYNAPSE FORECASTS

Figure 11: Utility non-zero and non-confidential reference case forecasts from 2012-2015

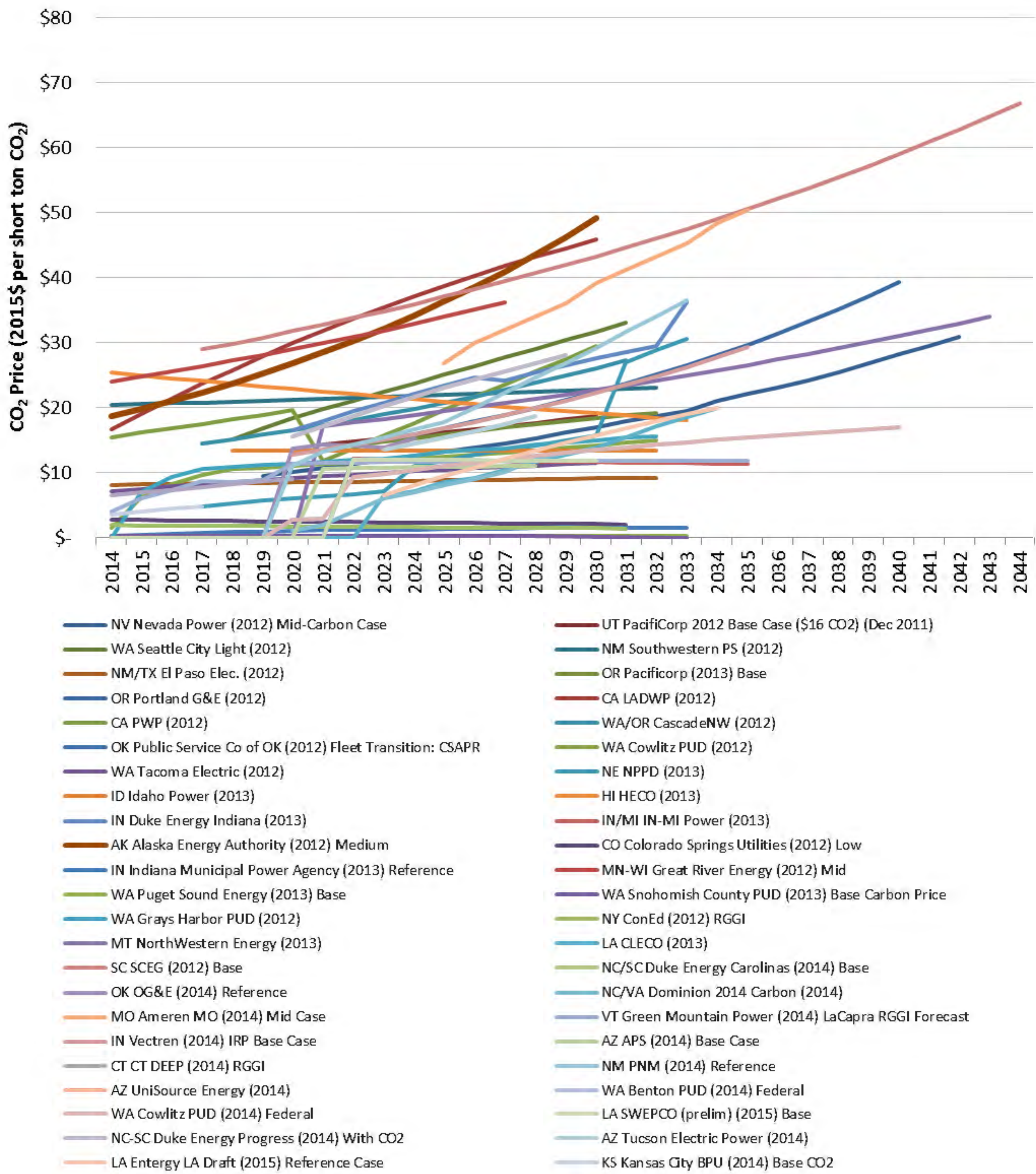
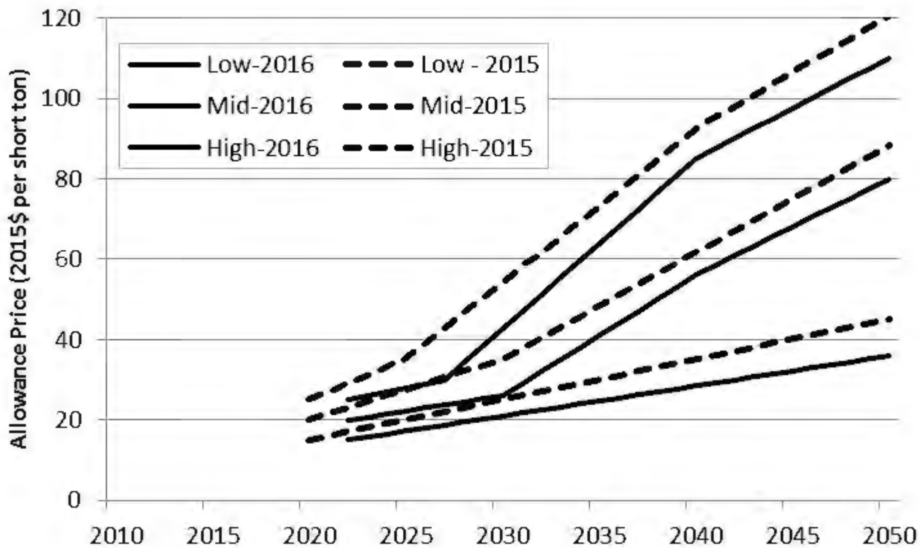


Figure 12 compares Synapse's 2016 and 2015 CO_2 price forecasts. These forecasts do not differ substantially. Two key differences are a tighter range of prices in 2020 resulting from greater policy certainty, and higher 2015 forecasts for the Mid and High cases, resulting from the indicated stringency of the Clean Power Plan. The 2015 forecast was the first Synapse forecast to extend to 2050.

Figure 12: Comparison of 2013 and 2015 Synapse CO_2 price forecasts



Source: Synapse Energy Economics, Inc. 2016.

Appendix B: Complementary Policies for Greenhouse Gas Reductions

- *National Ambient Air Quality Standards (NAAQS)* set maximum health-based air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10 micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)* establishes the obligations of each affected state to reduce emissions of NO_X and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. Implementation of CSAPR was delayed when the rule was vacated by the U.S. Court of Appeals for the District of Columbia in August 2012; it was then reinstated by the Supreme Court on April 29, 2014. Significantly, the Supreme Court found that EPA had not exceeded its authority in crafting an emission control program that utilized cap and trade and considered cost as a factor where the language of the Clean Air Act was ambiguous in addressing the complex problem of interstate transport of pollution. Phase I of the reinstated CSAPR has already begun; the more stringent requirements of Phase II begin January 1, 2017.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury and other metal toxins, organic and inorganic hazardous air pollutants, and acid gases. Compliance with MATS is required by 2015, with a potential extension to 2016. In July 2015, the U.S. Supreme Court remanded the MATS rule to the D.C. Circuit Court of Appeals, finding that EPA had failed to properly account for costs in determining whether it should regulate mercury. In December 2015, the D.C. Circuit Court rejected a request from coal interests to vacate the rule, leaving it in place while the EPA drafts its cost assessment per the Supreme Court's ruling. Many utilities have already undertaken the capital improvements at their coal plants to comply with the standard. In fact, in early 2014, EIA found that approximately 70 percent of U.S. coal-fired power plants already comply with MATS.[43]

- *Coal Combustion Residuals (CCR) Disposal Rule:* On December 19, 2014, EPA issued a final rule regulating CCR under Subtitle D of the Resource Conservation and Recovery Act. In the final rule, EPA designates coal ash as municipal solid waste, rather than hazardous waste, which allows its continued "beneficial reuse" in products such as cement, wallboard, and agricultural amendments. The rule applies to new and existing landfills and ash ponds and establishes minimum siting and construction standards for new CCR facilities. It requires existing ash ponds at operating coal plants to either install liners and ground water monitoring or permanently retire, and also sets standards for long-term stability and closure care. The rule also establishes a number of requirements for facilities to make monitoring data and compliance information available to the public

[43] See EIA website. Accessed December 17, 2015. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15611.

online. This is significant because the Subtitle D designation makes the CCR regulations "self-implementing," meaning EPA has no formal role in implementing or enforcing the regulations. Instead, enforcement is expected to be achieved through citizen suits under the Solid Waste Disposal Act. States may—but are not required to—incorporate the federal CCR requirements into their own solid waste management plans.

- *Steam Electric Effluent Limitation Guidelines (ELGs):* On September 30, 2015, EPA released its final steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways.[44] The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. New requirements for pretreatment must be in place by November 2018 and best available technology requirements will be implemented in 2018 through 2023 through the five-year National Pollutant Discharge Elimination System permit cycle.[45]

- *Cooling Water Intake Structure (§316(b)) Rule:* In March 2011, EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants that withdraw large volumes of water from nearby water bodies. Under this rule, EPA would set new standards to reduce the impingement and entrainment of fish and other aquatic organisms from cooling water intake structures at electric generating facilities. The final rule was released on May 19, 2014. The requirements of the rule will be implemented through renewal of a facility's NPDES permit, which must be renewed every five years, and will be determined on a case-by-case basis.[46]

- *Regional Haze Rule:* The Regional Haze Rule, released in July 1999, requires states to develop state implementation plans (SIPs) for reducing emissions that impair visibility at pristine areas such as national parks. The rule also requires periodic SIP updates to ensure progress is being made toward improving visibility, with a goal of achieving natural conditions by 2064. The initial round of SIPs requires Best Available Retrofit Technology (BART) controls for SO_X, NO_X, and PM emissions on large emission sources built between 1962 and 1977 that are found to be contributing to visibility impairment. BART controls must be installed within five years of SIP approval and no later than 2018.

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[44] See U.S. EPA website. Accessed December 17, 2015. Available at: http://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule.

[45] See U.S. EPA website. "Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Industry Factsheet." Accessed December 17, 2015. Available at: http://www.epa.gov/sites/production/files/2015-10/documents/steam-electric-final-rule-factsheet_10-01-2015.pdf.

[46] See U.S. EPA website. Accessed December 17, 2015. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.