BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan.	OPENING COMMENTS OF THE CITIZENS' UTILITY BOARD OF OREGON

I. INTRODUCTION

The Oregon Citizens' Utility Board (CUB) files these initial comments on Portland General Electric's (PGE or Company) November 2016 Integrated Resource Plan (IRP or Plan), filed on November 15, 2016. CUB will continue to conduct discovery and review the Company's plan prior to submission of Final Comments on March 31, 2017.

CUB recommends the Commission not acknowledge PGE's preferred portfolio because the Company's IRP analysis undervalues medium-term resources, underutilizes market purchases, and commits ratepayers to significant long-term investments in thermal resources despite numerous uncertainties that will likely reduce the Company's projected long-term capacity need.

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II. OVERVIEW

PGE has determined that the Company will need over 800 MWs of capacity by 2021.[1] The Company's determination of need is based on the assumption that load growth will be largely flat until 2020 but then increase by 1.5% every year through 2050.[2] To meet its projected need, PGE designed 21 portfolios evaluated against 23 potential future environments using the key variables of: fuel prices, carbon prices, load growth, capital costs, hydro availability, and renewable resource performance.[3] PGE's analysis produced four top-ranked portfolios that were found to have total weighed scores "that are very close to one another."[4] Indeed, PGE's first ranked, *Efficient Capacity* portfolio, and second ranked, *Wind 2018 Long* portfolio, are separated by only 2 out of 83 points on PGE's weighted score.[5]

PGE describes its top four ranked portfolios as having relatively diverse compositions of resources.[6] Notably, under PGE's selected preferred portfolio, the Company intends to meet at least half of its projected capacity need through a natural gas fired combined-cycle combustion turbine (CCCT).[7] In contrast, PGE's second and fourth ranked portfolios would "achieve[] the same expected available energy and capacity" through the addition of wind resources and some "generic capacity in 2021 as opposed to a CCCT."[8] PGE uses a natural gas-fired frame combustion turbine ("frame CT")[9] as the representative for generic capacity resources.[10]

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[1] PGE IRP at 340.
[2] PGE IRP at 101.
[3] PGE IRP at 30.
[4] PGE IRP at 337-338. *See also* p. 26 where PGE notes that "four of the top-ranked portfolios had relatively comparable performance to one another."
[5] PGE IRP at 337.
[6] PGE IRP at 338.
[7] *Id.* at 337-340, 278 (*See Efficient Capacity 2021* Portfolio), 810.
[8] PGE IRP at 278.
[9] Frame CTs are "scalable to exactly match the projected capacity needs." PGE IRP, p. 344.

However, PGE "acknowledges that there may be lower capital cost, higher variable cost resource options" such as contracts or existing plants that can also fill the Company's 'generic capacity' needs instead of the frame CT modeled in the IRP.[11]

As a consequence of its preferred portfolio, PGE intends to issue an RFP in 2018 to acquire "375 to 550 MW of long-term annual dispatchable [thermal] resources…"[12]

III. COMMENTS

In developing its IRP, PGE is obligated to evaluate all resources "on a consistent and comparable basis" including consideration of the risks and uncertainties associated with each resource. [13] PGE's preferred portfolio calls for a significant investment in a long-term thermal facility. As the Commission witnessed with PGE's Trojan[14], Boardman[15], and Carty[16] plants, some of the greatest risks posed by large long-term fossil-fuel based facilities is the risk of stranded assets, early retirement, and ratepayers being asked to shoulder the burden of cost overruns and mechanical failure.

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[10] PGE IRP at 212.
[11] PGE Response to OPUC DR No. 001, p. 8.
[12] PGE IRP at 344.
[13] OPUC Order 07-047, p. 1-2 (identifying a list of risks and unknowns that a utility must consider "at a minimum" including "load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.").
[14] OPUC Order 09-174 (UE 88), p. 1, 5/15/2009 (ordering PGE to refund customer $15.4 million in costs associated with mechanical failure at the Trojan Nuclear Plant).
[15] OPUC Order 10-457 (LC 48), p. 15-17, 11/23/2010 (ordering the shutdown of PGE's coal-powered Boardman plant in 2020, approximately 20 years before the end of its projected useful life).
[16] *PGE sues insurers for cost overruns on power plant; could turn to ratepayers next,* by Ted Sickinger, "The Oregonian", publicly available at: http://www.oregonlive.com/business/index.ssf/2016/03/pge_sues_insurers_for_cost_ove.html (March 26, 2016) (stating that PGE may seek recovery from ratepayers of $156 million in cost overruns of its new Carty gas-fired power plant).

Moreover, PGE has selected its preferred portfolio through a set of assumptions, but the underpinnings of those assumptions contain a historically high level of uncertainty and unknown variables. For example, under its preferred portfolio, PGE would acquire substantial long-term thermal resources despite the fact that: (1) medium-term[17] resources may be more cost effective to ratepayers; (2) market purchases may be a key component of a least-cost portfolio; (3) technological advances are likely to reduce projected load needs beyond what can be calculated today; and (4) significant transformations to the traditional utility model will only increase in future decades. For all of these reasons, the Company should be required to demonstrate how optionality and nimbleness of resources are treated in the portfolio selection and valuation process.

In contrast to PGE's proposed long-term investments, medium-term resources avoid the risk that, should the Company's projections be inaccurate or altered through changing circumstances, PGE and its customers will be saddled with stranded assets. PGE must "explain in its plan how its resource choices appropriately balance cost and risk"[18], yet PGE provides little to no discussion of the comparative risks associated with long versus medium-term resource acquisitions. For these reasons, CUB feels strongly that PGE should be required to explore medium-term resources before the Commission acknowledges the Company's preferred portfolio. Until PGE has tested the market and determined if medium-term resources can meet PGE's need, while mitigating the risks associated with the aforesaid uncertainties, any acknowledgment of PGE's preferred portfolio is premature.

[17] For purposes of these comments, CUB will refer to 5-10 year capacity resource acquisitions as "medium-term" investments.
[18] OPUC Order 07-047, p. 2.

A. *Medium-Term Resources May Be The Most Cost-Effective Way To Meet PGE's Need For The Next Ten Years*

To obtain the most cost-effective resources for its customers, PGE should be required to compare medium and long-term resources based on the life or contract length of the medium-term resource. When comparing two long-term resources against one another, it is sensible to consider the impact to ratepayers on the basis of levelized costs over the long-term. However, when comparing resources with very different terms (short, medium, or long), then consideration must be given to the shorter time period resource option.

Instead, PGE analyzes the costs of long and medium-term resources in a manner that favors the long-term resource, and increases the likelihood of committing to an asset that will result in stranded costs for either the Company or ratepayers. In doing so, PGE may be disfavoring resources that are more cost-effective and contain less stranded cost risks for ratepayers. CUB's Attachment A provides a model of the approximate amortized costs of a new hypothetical gas-fired power plant in its first, fifth, and tenth operating year. Attachment A is intended to demonstrate two important reasons why PGE's analysis of long and medium-term resource costs is problematic.

First, when contemplating a long-term resource, and comparing it against an alternate medium-term resource, the Company uses the net present value of the cost of the resource over its life, as compared to the market, to value the resource. To extend the life of the shorter term resource, PGE adds the levelized cost of a generic capacity resource for the remaining years of the analysis. As a result, when the Company compares a 5 year resource to a 30 year resource, 25 years of the comparison is actually comparing the 30 year resource to a generic capacity resource. PGE's IRP never considers whether a five-year resource could be a lower cost option during those first five years, because the five-year resource is re-designed to look like a 30-year resource.

Second, there is a mismatch in the way the Company treats its cost-benefit analysis of a potential investment with cost allocation of an existing asset. Rate-based resources are front-loaded in customer rates-that is they are more expensive in their early years. For example, the costs of the hypothetical gas plant modeled in CUB's Attachment A, is $33-44/MWH in the first of the plant's 30-45 year useful life.[19] As PGE's assets depreciate with time, the resource begins to become more economical.[20] In the case of the hypothetical gas plant, customers pay $32-41/MWH in the plant's fifth year and $30-38/MWH in the plant's tenth year.[21] CUB does not dispute that levelized cost analysis is appropriate for an asset that serves customers for many years. However, that economic argument only works if the plant actually serves at that level, without additional costs for the specified period of time, and the risks associated with our analysis (discussed below) tend to decrease over time.

What's more, PGE is committing to long-term investments, at a time when there are a historically high number of significant uncertainties and unknowns in the utility field (discussed below). PGE would likely argue that it is because of future uncertainties, and the ability to 'lock-in' many of the costs of generation, which make long-term resources attractive. But that logic cuts both ways. Investing in long-term resources brings increased risks when, as is true here, the bulk of uncertainties in PGE's resource planning are likely to undermine the Company's long-range projected load growth. Since that is the situation in this case, PGE

[19] See CUB's Attachment A (CUB notes that the attached spread sheet is an estimation of Carty 1 costs based on approximates and not on actual confidential data).
[20] CUB's Attachment A.
[21] CUB's Attachment A.

should be pursuing medium-term resources and determining if they offer the kind of optionality which would meet PGE's projected need with less risk to ratepayers.

B. *Market Purchases May Be a Key Component of a Least Cost Portfolio*

By eliminating market purchases to meet the Company's load, PGE is likely ignoring a valuable option to creating a least-cost portfolio. As is evident from CUB's Attachment B, market purchases are no longer a part of the Company's power supply (though they are still used for system balancing).[22] Just four years ago, in 2013, purchased power made up 35% of PGE's power supply. This year it is expected to be 0%.[23]

Market prices are generally low due to a number of factors including, an increase in RPS targets in Oregon and other Western states, and an increase in customer generation. Indeed, PGE's forward price curve shows continued low market prices over the next five years.[24] Yet, PGE has continued to invest in new natural gas power plants in recent years resulting in a growing amount of gas generation and an elimination of market purchases. With market prices low, PGE is missing out on the opportunity to obtain some of its power supply from the low-cost market.

While PGE must plan for a reliable future, it does not appear to be fully exploring more targeted capacity resources that would serve the Company's reliability and capacity needs. Based on PGE's own projections, market purchases may be a least-cost option to make up, at least a segment, of the Company's power supply.

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[22] CUB's Attachment B, p. 25 (pie graph demonstrating to investors PGE's "Changing Generation Portfolio").
[23] CUB's Attachment B, p. 25.
[24] PGE IRP, Appendix H at 630 (notably PGE's forward price curve begins to rise after 5 years, which is when PGE's planning assumption begins adding carbon prices).

C. *Technology Changes Are Likely to Outpace PGE's Long-Range Load Growth Assumptions*

Rapid technological developments in demand response ("DR"), energy efficiencies ("EE"), and energy storage will increasingly reduce PGE's projected long-range need for new capacity resources.[25] Already these developments, combined with a precipitous decline in costs, have allowed other states to implement innovative demand-side and energy storage programs.[26] PGE discusses the considerable changes and the rapid rate of technological progress in the areas of energy storage and advanced DR throughout the IRP.[27] However, because those technological advances are still being tested and developed, PGE is in a poor position to predict the impact DR, EE, and storage will have on its capacity needs in 10, 20, let alone 30 years.

Moreover, PGE does not appear to be aggressively pursuing robust energy storage or DR programs even with the technology that is known at this time. PGE's preliminary storage investigation[28] found a number of system peaking and operational benefits, and the Company recognized that "as technology costs continue to decline, the economics of battery storage on the

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[25] *See* PGE Response to OPUC DR No. 001, p. 5 ("PGE recognizes that rapid technological development in the DR field has the potential to make additional DR available earlier than anticipated.").

[26] *See, Massachusetts Goes All-In on Energy Storage;* by Todd Olinsky-Paul, "Renewable Energy World" (Sept. 2, 2016), publicly available at: http://www.renewableenergyworld.com/articles/2016/09/massachusetts-goes-all-in-on-energy-storage.html (discussing Massachusetts commitment to emerging energy storage technologies which are projected to create 600 MW in new advanced storage capacity by 2025); CUB's Attachment C (*OG&E's Smart Hours: from Pilot to Program* by Kelly Marin & Jessica Bryant. Power Point presentation discussing Oklahoma's OGE's SmartHours demand response program which: provides approximately 156 MW of capacity, guaranteed no harm to its customers in the first year, and allowed OGE to avoid building new thermal capacity).

[27] PGE IRP at 31, 35, 246.

[28] PGE IRP at 235.

PGE system may rapidly evolve…"[29] Yet, PGE does not project acquiring energy storage in the future beyond the 5 MWh required by HB 2193.[30] Similarly, the Company admits that its DR inputs undervalued the amount of DR the Company had calculated as achievable by 2021 by at least 100 MW.[31] When pressed, PGE rationalized a "gradual growth" approach to DR based on factors largely within the Company's control.[32]

Finally, PGE commits to obtain all "cost-effective energy efficiency" based on energy efficiency studies conducted by the Energy Trust.[33] While CUB approves of PGE's pursuit of EE, it is worth noting that the Energy Trust's EE estimates are based on what is known and achievable in the near future. Historically, EE has continued to grow and outpace the Energy Trust's long-term EE projections. Accordingly, even the Energy Trust's valuable EE studies have limited bearing on the impact EE will have 15, 20, or 30 years from now.

D. *Transformations in the Utility Sector Will Render Many of PGE's Long-Range Assumptions Inaccurate*

Like the technological advances discussed above, distributed generation ("DG") and increased integration of energy markets across the West will continue to reduce PGE's projected long-term needs. "PGE's load forecast does not include any explicit adjustment to historical loads to account for customer-sited solar, nor does the forecast contain assumptions about the

[29] PGE IRP at 246.
[30] PGE IRP at 230, 246.
[31] PGE Response to OPUC DR No. 074.
[32] PGE Response to OPUC DR No. 074 (explaining slower growth in DR based on low customer awareness, and some stakeholder opposition to opt-out, as opposed to opt-in, pricing programs).
[33] PGE IRP at 31, 358.

potential for accelerated growth rates of this resource."[34] Nor has PGE taken into account any projections regarding community solar and its potential impact on PGE's available capacity.[35]

Moreover, PGE's IRP analysis employs a total reserve margin ranging from 17-20% until 2040. [36] PGE attributes its use of a historically high reserve margin to increased penetration of wind and solar resources.[37] At the same time, PGE is actively working towards joining the Western Energy Imbalance Market (EIM)[38], and there is a growing push to expand the California Independent System Operator (CAISO) into a regional ISO[39]. PGE's long-term projected reserve margins may very well be an over-estimation given the fact that: a regional energy market would likely increase the ability to efficiently integrate renewables onto the market; and membership in an ISO usually allows participants to carry a reduced reserve margin than those utilities operating outside of an ISO.[40]

Finally, PGE's IRP model assumed the Company would pursue long-term physical hedging to mitigate risks of volatility in the cost of natural gas. However, in Docket UE 308, the Commission recently denied PGE's request to engage in long-term physical hedging.[41] PGE has not supplemented its IRP to address this changed circumstance.

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[34] PGE IRP at p. 104.
[35] *See* PGE IRP at pp. 184-185 (discussing three main forms of DG, including net-metering, but without any mention of Community Solar).
[36] PGE IRP, Appendix P, p. 850.
[37] PGE IRP, p. 47.
[38] PGE IRP, p. 48.
[39] PGE IRP, p. 95-96.
[40] *See e.g., Planning Year 2014-2015 MISO Planning Reserve Margin Results;* publicly available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2013/20131002/20131002%20LOLEWG%20Item%2004b%20Draft%20Report%20%20-%20Sections%205%20and%206%20PRM%20Results.pdf (requiring a 14.8% reserve margin of MISO members).
[41] OPUC Order 16-419 (Oct. 27, 2016).

IV. CONCLUSION AND RECOMMENDATION

As a final note, CUB wants to emphasize that it understands that the Company cannot predict the future and that forecasts are always wrong. CUB does not fault the Company for being unable to exactly predict the contribution DR, EE, and storage will make to PGE's capacity resources in 15, 20, or 30 years. But, given these uncertainties, CUB does take issue with committing PGE ratepayers to a significant long-term investment in a thermal resource without first determining if medium-term resources would be the appropriate least-cost and least-risk resource instead. Pursing medium-term resources may be the best course to allow PGE time to better understand the value of new technologies and the implications of DG and integrated Western markets.

Furthermore, increases in RPS thresholds and net metering are leading to lower market prices for energy. This in turn has reduced the value of this region's hydro sales for resale. Entities that used to rely on selling hydro into the market to create value are now looking for new ways to create economic value with hydro sales. CUB believes the timing maybe be right for the Company to issue an RFP to test the market and see what capacity contracts are available.

For these reasons, CUB recommends that the Commission: (1) not acknowledge the Company's preferred portfolio and (2) require PGE to issue an RFP for resources that are between 2 and 10 years in length, with no minimum size, and with seasonal products allowed.

Signed this 24th of January, 2017.

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Portland, OR 97205
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CUB Attachment A
Low and High Estimates of Cost of New Gas Plant in $/MWH

	Low	High	source
total cost of gas plant	514,000,000	660,000,000	general range for Carty 1
useful life	45 years	30 years	
average annual depreciate	11,422,222.22	22,000,000	
pretax ROR year 1	50,257,778	63,800,000	assumes 10% ***pretax*** RoR
average annual energy	357 aMW	357	based on Carty 1
average annual energy MWH	3,127,320	3,127,320	
fixed cost recovery per MWH year 1	16.07	20.40	
O&M	10,000,000	10,000,000	general estimate PGE plants
A&G and insurance	1,500,000	1,600,000	
property taxes	2,400,000	2500000	
Fuel cost per $/MWH	18	24	EIA data
Carty first year per MWH			
capital costs recovery	3.652	7.035	
pre tax return on investment	16.071	20.401	
O&M, A&G and Property taxes	4.445	4.509	
fuel costs	18.000	24.000	
total cost per MWH	42.168	55.944	
year 5 (assuming no increase in fuel)			
pretax ROR year 5	45,688,888.889	55,000,000.000	
per MWH	14.610	17.587	
total cost per MWh year 5	40.71	53.13	
year 10			
pretax ROR	39,977,778	44,000,000	
per MWH	12.783	14.070	
total cost year 10	38.880	49.613	

Portland General Electric

Investor Presentation
December 2016

Cautionary Statement

Information Current as of October 28, 2016

Except as expressly noted, the information in this presentation is current as of October 28, 2016 — the date on which PGE filed its Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 — and should not be relied upon as being current as of any subsequent date. PGE undertakes no duty to update the presentation, except as may be required by law.

Forward-Looking Statements

Statements in this news release that relate to future plans, objectives, expectations, performance, events and the like may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include statements regarding earnings guidance; statements regarding the expected capital costs for the Carty Generating Station and the recovery of those costs; statements regarding future load, hydro conditions and operating and maintenance costs; statements concerning implementation of the company's integrated resource plan; statements concerning future compliance with regulations limiting emissions from generation facilities and the costs to achieve such compliance; as well as other statements containing words such as "anticipates," "believes," "intends," "estimates," "promises," "expects," "should," "conditioned upon," and similar expressions. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties, including reductions in demand for electricity; the sale of excess energy during periods of low demand or low wholesale market prices; operational risks relating to the company's generation facilities, including hydro conditions, wind conditions, disruption of fuel supply, and unscheduled plant outages, which may result in unanticipated operating, maintenance and repair costs, as well as replacement power costs; failure to complete capital projects on schedule or within budget, or the abandonment of capital projects, which could result in the company's inability to recover project costs; the costs of compliance with environmental laws and regulations, including those that govern emissions from thermal power plants; changes in weather, hydroelectric and energy markets conditions, which could affect the availability and cost of purchased power and fuel; changes in capital market conditions, which could affect the availability and cost of capital and result in delay or cancellation of capital projects; the outcome of various legal and regulatory proceedings; and general economic and financial market conditions. As a result, actual results may differ materially from those projected in the forward-looking statements. All forward-looking statements included in this news release are based on information available to the company on the date hereof and such statements speak only as of the date hereof. The company assumes no obligation to update any such forward-looking statement. Prospective investors should also review the risks and uncertainties listed in the company's most recent annual report on form 10-K and the company's reports on forms 8-K and 10-Q filed with the United States Securities and Exchange Commission, including management's discussion and analysis of financial condition and results of operations and the risks described therein from time to time.

PGE Value Drivers

Portland General Electric

Clear focus: 100% regulated utility

Attractive service area

Progressive environmental and renewable position

Focus on operational effectiveness and efficiency

Strong financial position

Generation and T&D resiliency initiatives strengthen infrastructure

STRONG PLATFORM FOR STAKEHOLDER VALUE

Portland General Electric

The Company

The Strengths

The Execution

PGE at a Glance

Quick Facts:

- Vertically integrated generation, transmission and distribution
- ~863,000 customers[(1)]
- 46% of Oregonians
- Majority of Oregon's commercial and industrial activity

Financial Snapshot[(2)]:

Revenue: $1.9 billion

Earnings per share: $2.04

Net Utility Plant Assets: $6.0 billion

(1) As of 9/30/2016
(2) As of 12/31/2015

Strategic Direction

Portland General Electric

Mission: To be a company our customers and communities can depend upon to provide electric service in a safe, sustainable and reliable manner, with excellent customer service, at a reasonable price.

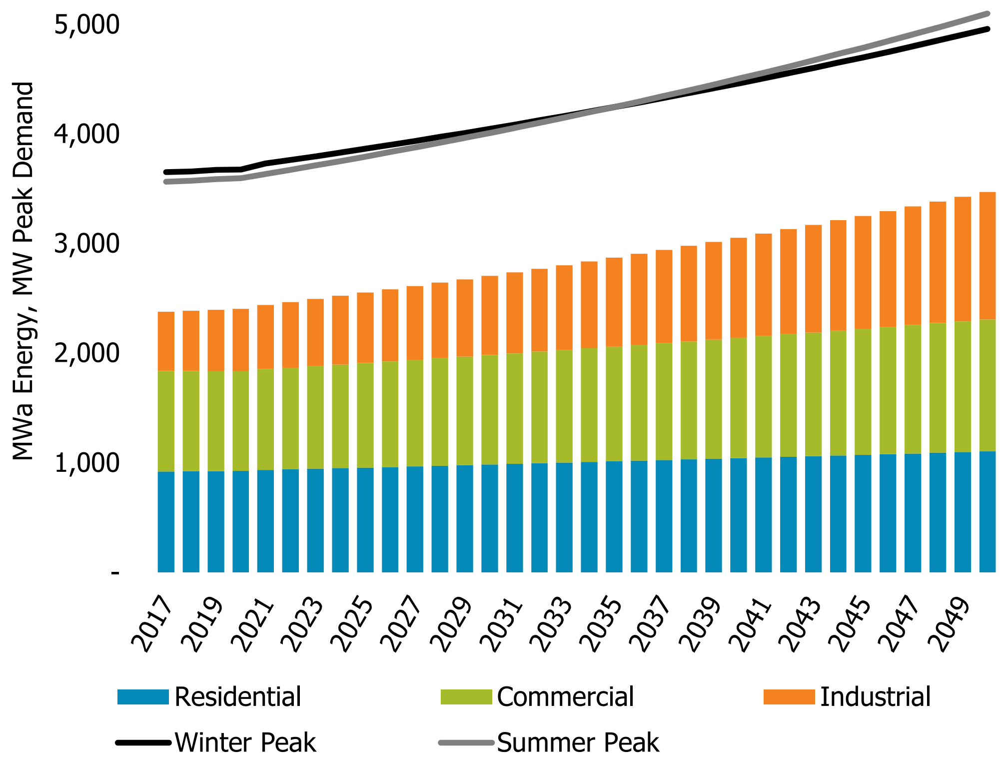
The path forward is guided by:

- Strong relationships with customers and community
- Empowering employees
- Opportunity to grow the business
- Delivering value to all stakeholders

Attractive, Growing Service Area

Portland General Electric

Long-Term Load Growth



- Long-term forecast ~1% annually through 2050
- Driven by:
  - Residential customer growth
  - Industrial deliveries growth
  - Energy efficiency

Constructive Regulatory Environment

Portland General Electric

Regulatory Construct

- Oregon Public Utility Commission
- 9.6% allowed return on equity
- 50% debt and 50% equity capital structure
- Forward test year
- Integrated Resource Planning (IRP)
- Renewable Portfolio Standard (RPS)

Governor-appointed three-member commission

Chair:	Lisa Hardie [D][1]	May 2020
	John Savage [D]	Mar 2017
	Stephen Bloom [R]	Nov 2019

Regulatory Mechanisms

- Net variable power cost recovery
  - Annual Power Cost Update Tariff (AUT)
  - Power Cost Adjustment Mechanism (PCAM)
- Decoupling through 2019
- Renewable Adjustment Clause

(1) Newly appointed at the end of May 2016

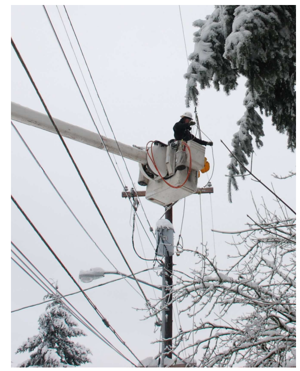
STRONG PLATFORM FOR STAKEHOLDER VALUE

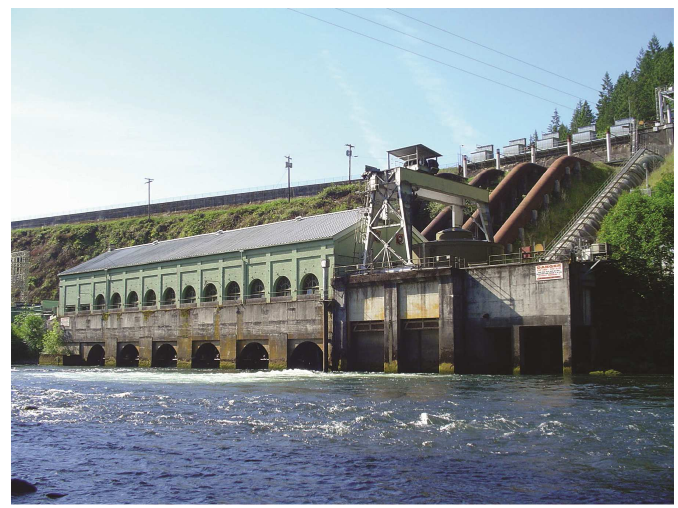
Portland General Electric

The Company

The Strengths

The Execution





Key Strengths

Portland General Electric

1. High customer satisfaction
2. Diverse generation and customer base
3. High quality utility operations
4. Solid financial performance
5. Strong financial position

1. High Customer Satisfaction

Top Quartile System Reliability
Edison Electric Institute

Top Quartile Customer Satisfaction
TQS Research, Inc.

Most Trusted Brand & No. 1 for Dedication to the Environment
Market Strategies International

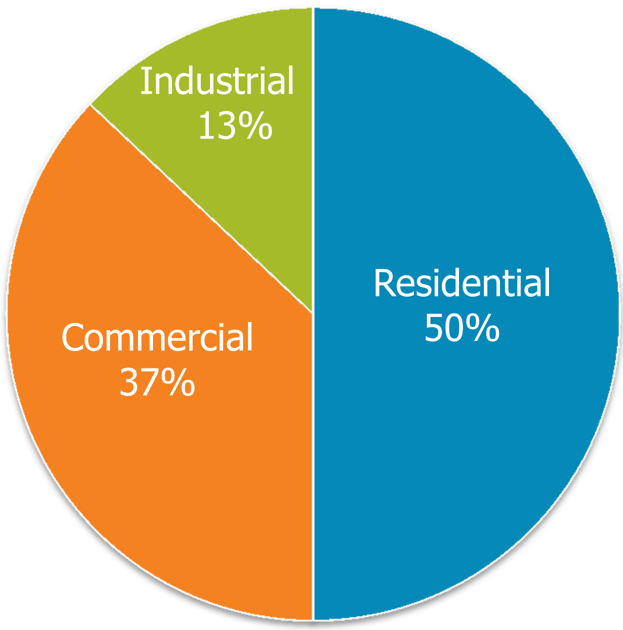
Top Ranked Renewable Energy Program
National Renewables Energy Laboratory

All customer satisfaction and reliability measures consistently top quartile

2. Diverse Generation and Customer Base

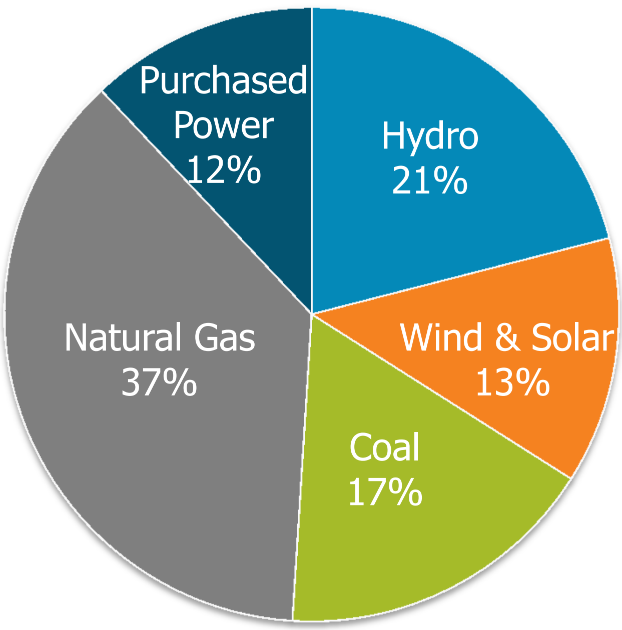
Retail Revenues by Customer Class
(2015)

Total = $1.78B



Power Sources as a Percent of Retail Load
(2016 AUT)[1]

Total = 2,120 MWa



(1) Hydro and wind/solar include PGE owned and contracted resources; purchased power includes long-term contracts

3. High Quality Utility Operations

Portland General Electric

- Highly dependable PGE generation portfolio with five-year average availability of 92%[(1)]
- Strong power supply operations to stabilize and optimize power costs
- Progressive approach to reduce coal generation – Boardman 2020 Plan and Colstrip 2035 Plan
- Generation and T&D initiative focused on improving efficiency, reliability and resiliency to meet customer needs and expectations
- Ongoing investment in technology to improve service and capture efficiencies

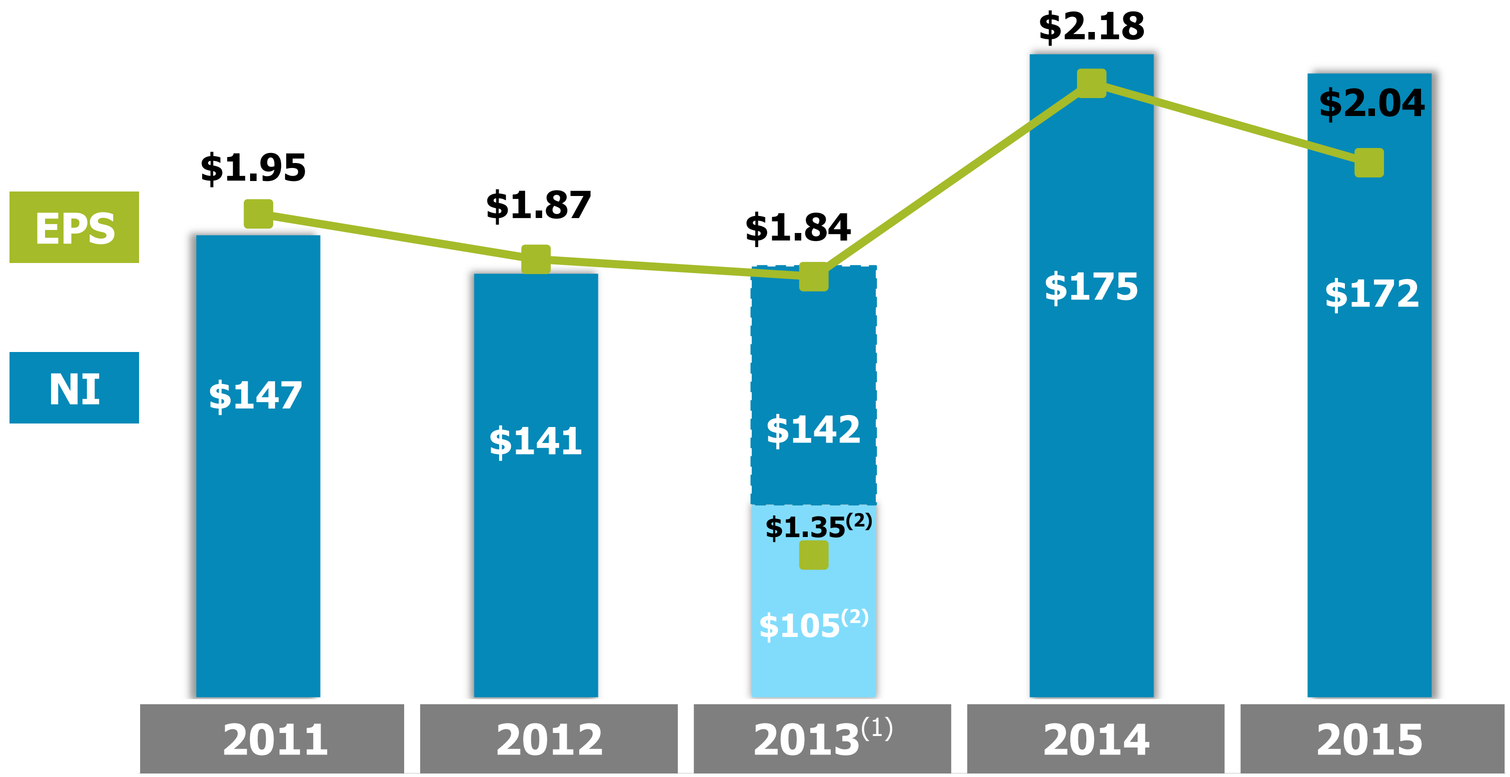
High Quality Utility Operations

(1) Represents 2011 through 2015

4. Solid Financial Performance

Net Income, Earnings per Share, and ROE 2011 – 2015

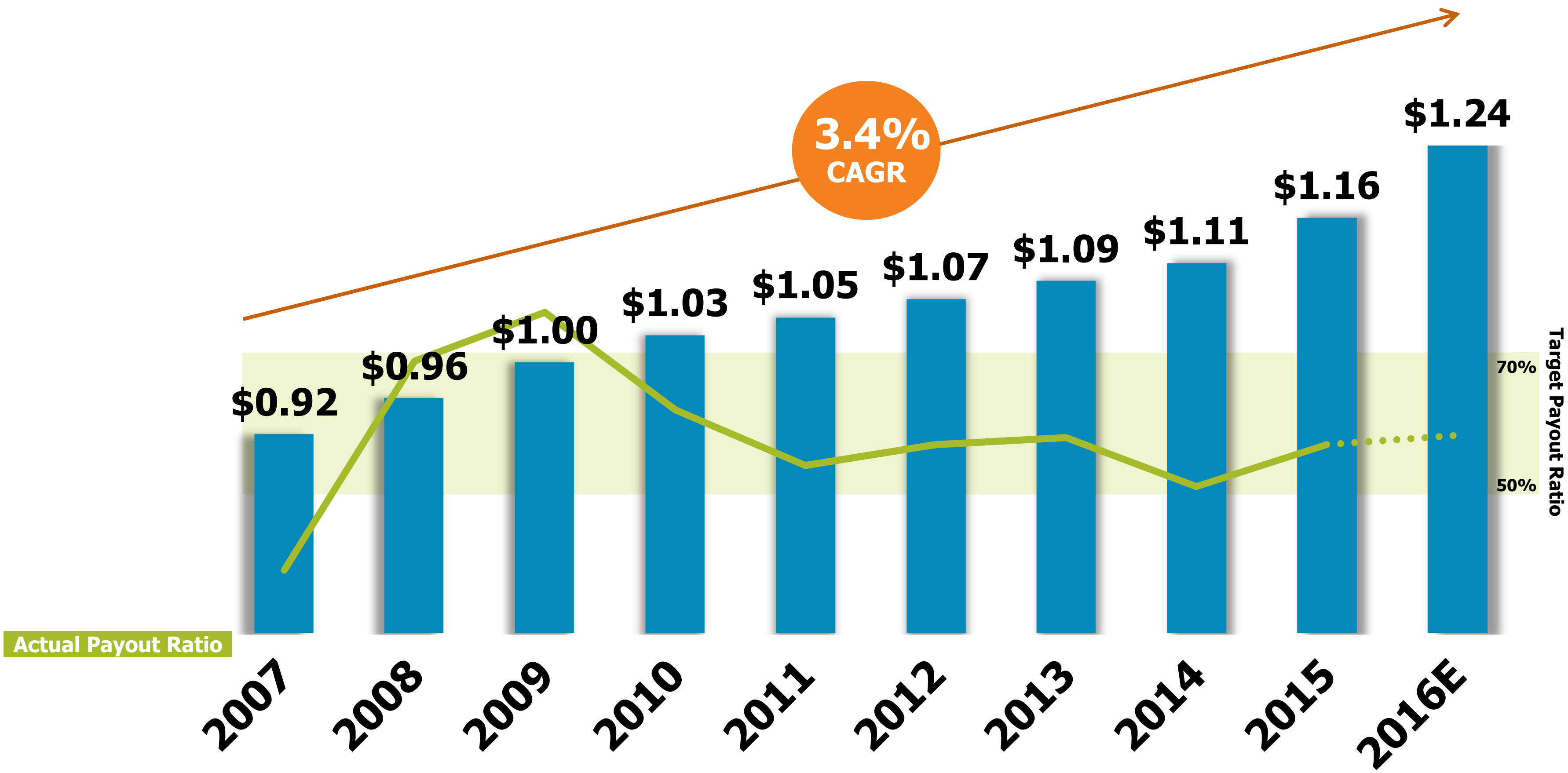
(NI in millions)



	2011	2012	2013(1)	2014	2015
ROE	**9.0%**	**8.3%**	**7.9%**	**9.4%**	**8.3%**
Allowed ROE	10.0%	10.0%	10.0%	9.75%	9.68%

(1) 2013 displays full-year non-GAAP adjusted operating earnings, which excludes the negative impact of the Cascade Crossing expense ($0.42 EPS) and the customer billing refund ($0.07 EPS)
(2) GAAP earnings for year-end 2013 were $105 million or $1.35 per diluted share

4. Consistent Dividend Growth



Annual dividend increases expected to be in the 5-7% range[1]

Note: Represents annual dividends paid

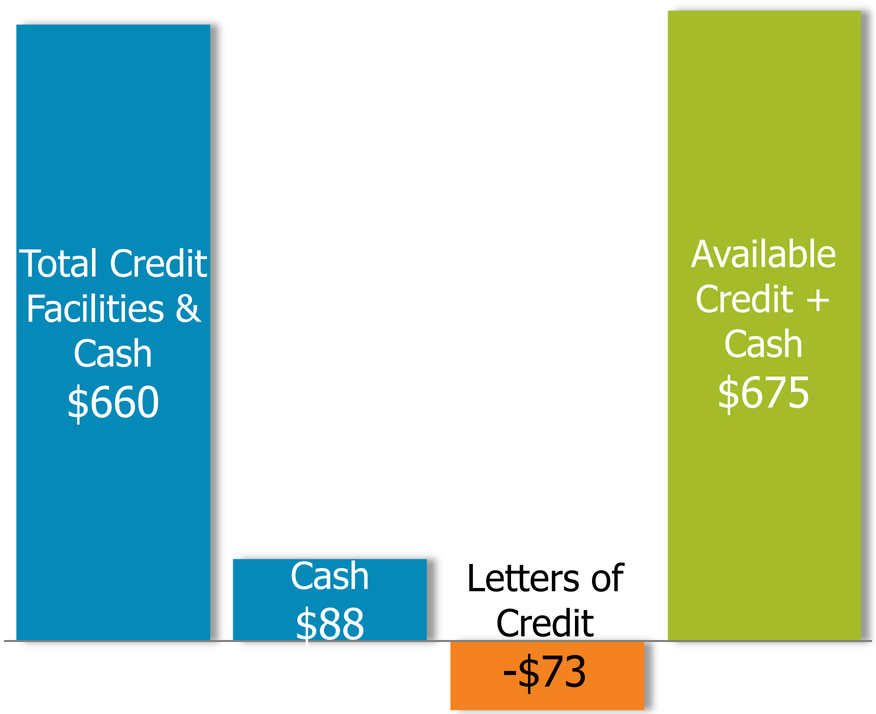
(1) Based on the company achieving earnings and cash flow estimates and other factors influencing dividends and subject to approval of the Board of Directors

5. Strong Liquidity Position for Growth

Portland General Electric

Revolving Credit Facilities[1]

(in millions)



Financial Resources

- Investment grade credit ratings
- Manageable debt maturities
- Target capital structure of 50% debt and 50% equity

	S&P	Moody's
Senior Secured	A-	A1
Senior Unsecured	BBB	A3
Outlook	Stable	Stable

(1) All values as of 9/30/2016

STRONG PLATFORM FOR STAKEHOLDER VALUE

Portland General Electric

The Company

The Strengths

The Execution

New Generation: Baseload Resource

Portland General Electric

Carty Generating Station: Placed in-service on July 29, 2016

Carty Generating Station, a 440 MW natural gas baseload plant near Boardman, OR

Capital costs, including AFDC, approved in 2016 GRC:	$514M
Total estimated cost, including AFDC, for completion:	$640-$660M(1)
Carty plant in service as of 9/30/2016:	$615M
Estimated time frame to complete litigation:	2-4 years

(1) Total estimated cost does not reflect any amounts that may be received from sureties under the performance bond, the original contractor, or contractor's parent company

2016 Integrated Resource Plan

Portland General Electric

Continuing PGE's shift to a less carbon-intensive portfolio

Areas of Focus

- Energy efficiency (135 MWa) and demand side actions (77 MW)
- Investment / acquisition of renewables (175 MWa) to meet Oregon Clean Electricity Plan: IRP will position PGE to comply with 27% requirement by 2025
- Filling up to 850 MW capacity deficit to ensure reliability
  - 375-550 MW long-term annual dispatchable resources
  - Up to 400 MW annual capacity resources

IRP Timeline proposed to OPUC

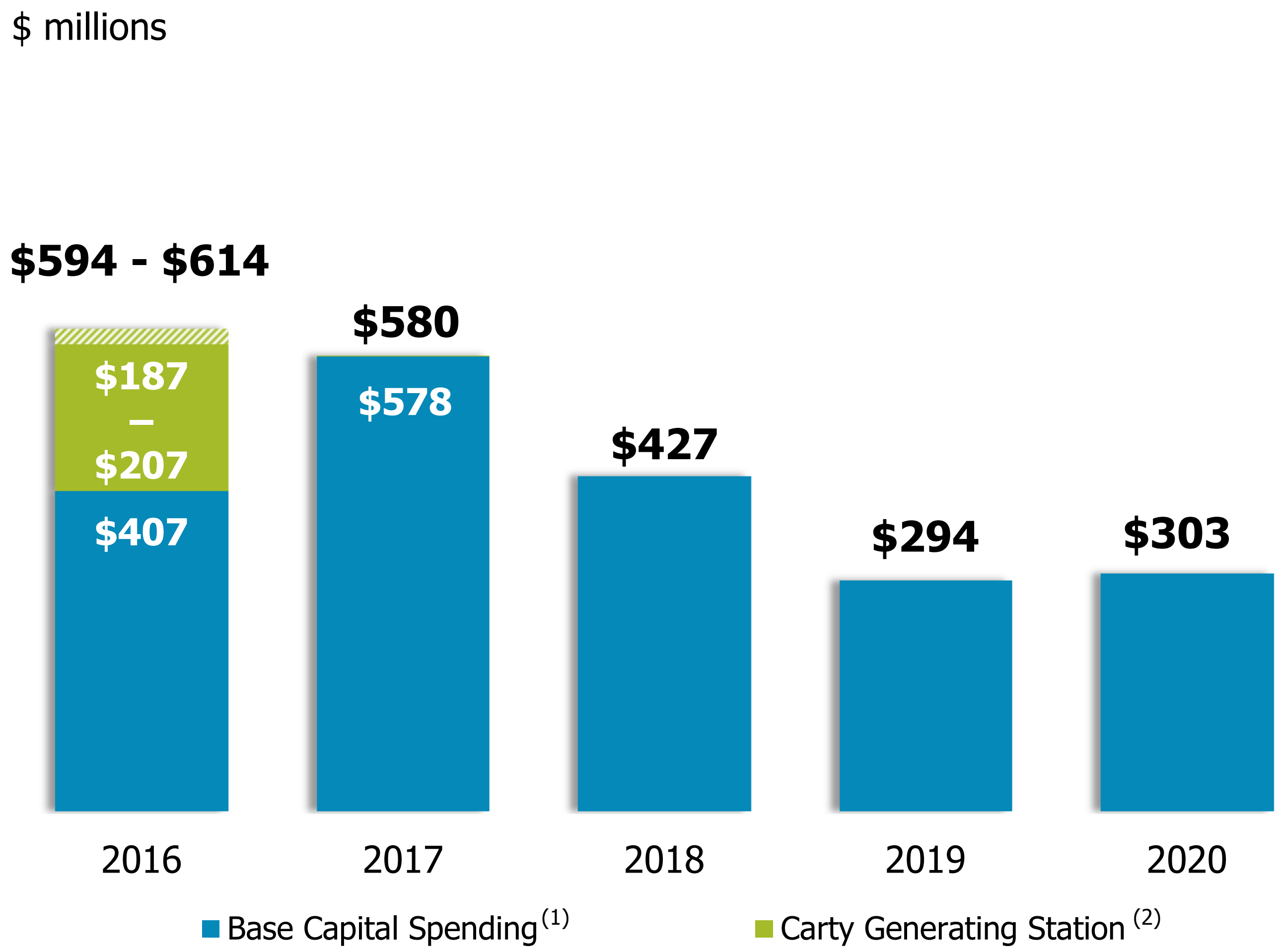
- Nov. 15, 2016: Filed IRP OPUC Docket LC-66
- Mid-2017: OPUC acknowledgment requested

Next steps, post acknowledgment

- 2nd Half 2017: RFP process commences
- 2018: Expected to reach decisions on RFPs

Forecasted Capital Expenditures

Portland General Electric



Outlook

Additional spending has been approved by the board of directors as part of a longer term program focused on improving the efficiency, reliability and resiliency of PGE's infrastructure to meet customer needs.

Capital additions that could result from the Request For Proposal following acknowledgment of the Integrated Resource Plan have not been estimated and are not shown.

Note: Amounts do not include AFDC

(1) Consists of board-approved ongoing Cap Ex and hydro relicensing per the Form 10-Q filed on October 28, 2016

(2) Total estimated cost does not reflect any amounts that may be received from sureties under the performance bond, the original contractor, or contractor's parent company

PGE Value Proposition

Portland General Electric

- High quality utility operations
- Attractive service territory
- Strong financial position
- Progressive reduction in carbon footprint & intensity
- Generation and T&D resiliency initiatives
- Future infrastructure investment opportunities

Strong Platform executing **Sustained Long Term Growth**

PGE Investor Relations Team

Portland General Electric

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Portland General Electric

Appendices

Diversified Resource Mix

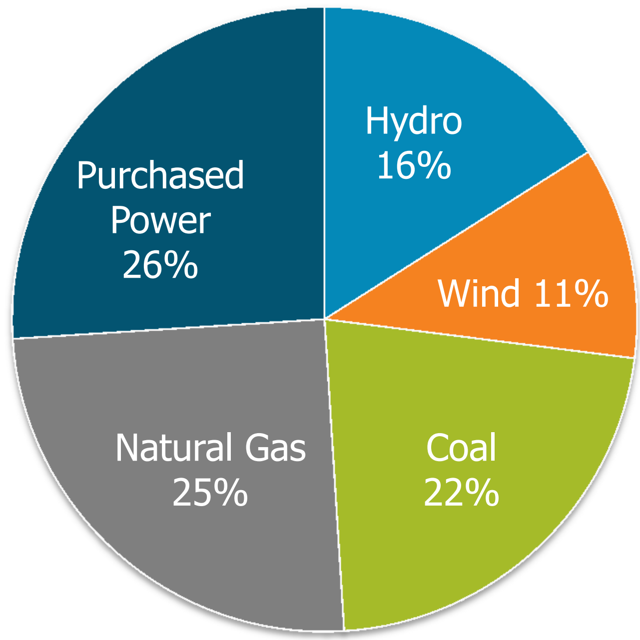
Portland General Electric

Resource Capacity[1]
as of 12/31/2015

	Capacity in MW	% of Total Capacity
Hydro[2]		
Deschutes River Projects	303	7%
Clackamas/Willamette River Projects	192	4%
Hydro Contracts	592	13%
	1,087	**24%**
Natural Gas/Oil[2]		
Beaver Units 1-8	508	11%
Coyote Springs	243	5%
Port Westward Unit 1	395	9%
Port Westward Unit 2	225	5%
	1,371	**30%**
Coal[2]		
Boardman	518	11%
Colstrip	296	6%
	814	**17%**
Wind		
Biglow Canyon[3]	450	10%
Tucannon River[4]	267	6%
Wind and Solar Contracts	52	1%
	769	**17%**
Purchased Power	**568**	**12%**
Total	**4,609**	**100%**

Power Sources as a Percent of Retail Load
(2015 Actuals)

Total = 18,831,000 MWh

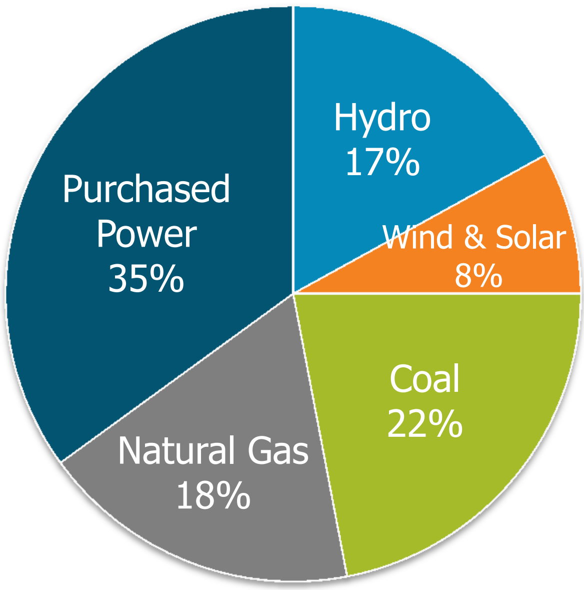


(1) Carty, a 440 MW natural gas plant, was added as a resource on July 29, 2016 and will be included in the 12/31/2016 disclosure.
(2) Capacity of a given plant represents the megawatts the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant.
(3) With respect to Biglow Canyon, capacity represents nameplate and differs from expected energy to be generated, which was a 26% capacity factor in 2015.
(4) With respect to Tucannon River Wind Farm, capacity represents nameplate and differs from expected energy to be generated, which was a 32% capacity factor in 2015.

Changing Generation Portfolio

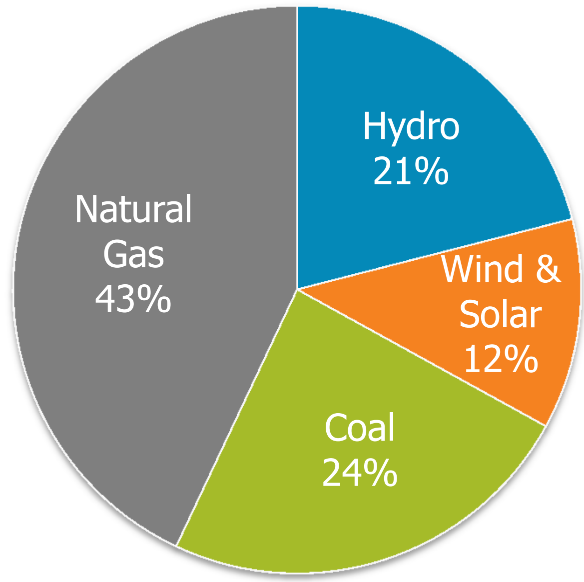
Portland General Electric

2013 Power Sources as a Percent of Retail Load
(2013 Actuals)



4 years later

2017 Power Sources as a Percent of Retail Load
(2017 Estimate)(1)



Changes driven by:

- New generation: Port Westward Unit 2 (natural gas, Q4 2014), Tucannon River (wind, Q4 2014), and Carty (natural gas, July 2016)
- Next requirements under Oregon's RPS (requiring a portion of PGE's retail load to be serviced by renewable resources): 20% by 2020, 27% by 2025, 35% by 2030, 45% by 2035 and 50% by 2040

(1) Based on an estimated forecast which includes new generation from Carty
Note: For both charts, hydro and wind/solar include PGE owned and contracted resources

Financing Activity

Portland General Electric

Equity Issuances

	Date	Shares	Net Proceeds
Equity Forward Sale Agreement	June 2013	11.1 million	--
Draw pursuant to forward	August 2013	0.7 million	$20 million
Draw pursuant to forward	June 2015	10.4 million	$271 million
Net remaining shares available for issuance:		0	
Equity Over-Allotment	June 2013	1.7 million	$46 million

Long-term Debt ($ in millions)

Issued:

Amount	Issuance Date	Coupon	Maturity
$100	8/15/14	4.39%	2045
$100	10/15/14	4.44%	2046
$80	11/17/14	3.51%	2024
$75	1/15/15	3.55%	2030
$70	5/19/15	3.50%	2035
$140	1/6/16	2.51%	2021
$50	5/4/16	~1.1%	Nov 2017
$75	6/15/16	~1.1%	Nov 2017
$25	10/31/16	~1.1%	Nov 2017

Matured/Redeemed:

Amount	Date
$70	Matured – Jan 2015
$67	Redeemed – May 2015
$75	Redeemed – Jan 2016
$58	Redeemed – Jan 2016

Generation Plant Operations

Portland General Electric

- **Track record of high availability**

	2011	2012	2013	2014	2015
PGE Thermal Plants	90%	92%	84%	89%	89%
PGE Hydro Plants	100%	99%	100%	100%	99%
PGE Wind Farm	97%	98%	98%	94%	97%
PGE Wtd. Average	**93%**	**94%**	**89%**	**92%**	**93%**
Colstrip Unit 3 & 4	84%	93%	66%	83%	93%

- **Generation Reliability and Maintenance Excellence Program**
  - Corporate strategy started in 2007 to increase availability of PGE's generation plants and increase predictability of plant dispatch costs for power operations
  - Key Elements
    - Reliability Centered Maintenance (RCM) modeling for PGE's generating plants and incorporation of models into PGE's maintenance management system (Maximo)
    - Root Cause Analysis (RCA) for unplanned generation outages, which expedites communication across PGE's fleet on both resolution and prevention actions
    - Internal training on technical skills, including inspection, welding and metallurgy – supporting both RCM and RCA efforts

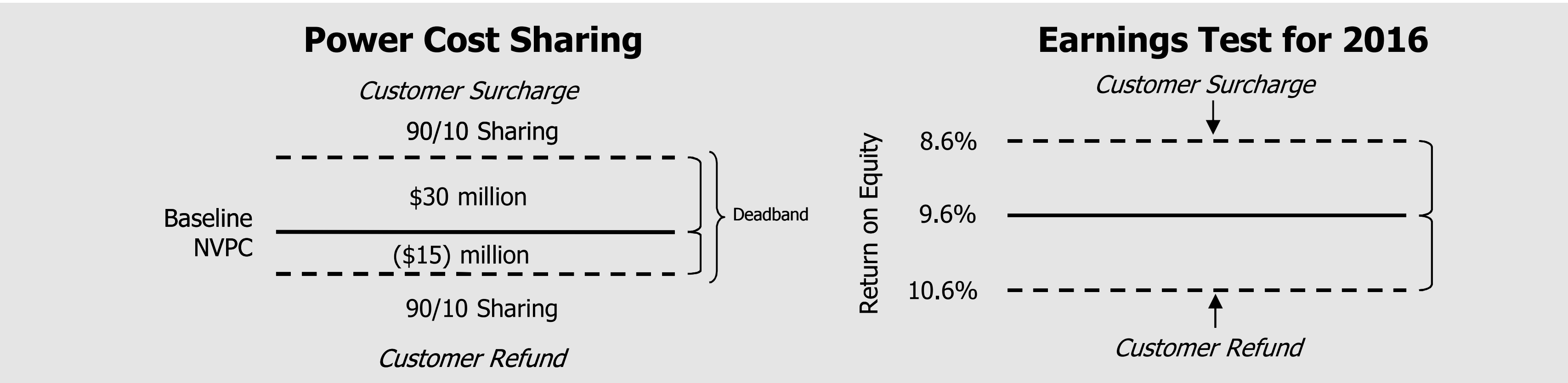
Recovery of Power Costs

Portland General Electric

Annual Power Cost Update Tariff

- Annual reset of prices based on forecast of net variable power costs (NVPC) for the coming year
- Subject to OPUC prudency review and approval, new prices go into effect on or around January 1 of the following year

Power Cost Adjustment Mechanism (PCAM)



- PGE absorbs 100% of the costs/benefits within the deadband, and amounts outside the deadband are shared 90% with customers and 10% with PGE
- An annual earnings test is applied, using the regulated ROE as a threshold
- Customer surcharge occurs to the extent it results in PGE's actual regulated ROE being no greater than 8.6%; customer refund occurs to the extent it results in PGE's actual regulated ROE being no less than 10.6%

2016 General Rate Case

Portland General Electric

Oregon Public Utility Commission Order

- Overall increase in customer prices: 0%
- Return on Equity: 9.6%
- Capital Structure: 50% debt, 50% equity
- Cost of Capital: 7.51%
- Rate Base: $4.4 billion(1)
- Annual revenue requirement increase: $12 million

Customer Prices

- Base Business: January 1, 2016
- Carty: August 1, 2016

Customer price changes:

  - Base business reduction of 2.5%
  - Carty increase of 2.5%

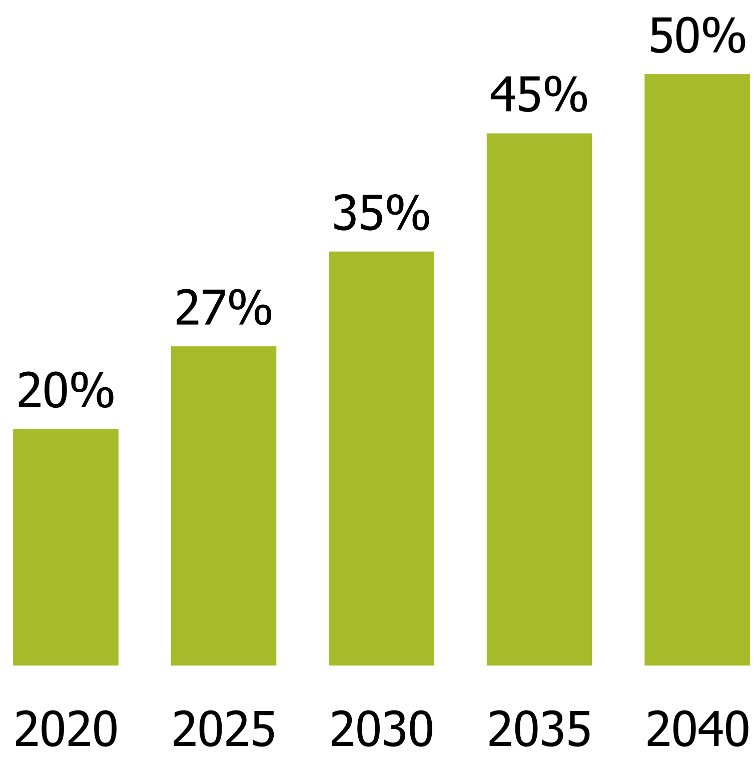
(1) Includes Carty at $514 million

Clean Electricity Plan and Coal Transition Plan

Portland General Electric

Key Elements of Plan

- Increase the renewable portfolio standard to 50 percent in 2040
- Transitions Oregon off coal-fired generation by 2035
- Includes PTCs in power costs, beginning with AUT filing for 2017
- Reaffirms state's commitment to energy-efficiency programs
- Encourages transportation electrification
- Increases access to solar energy for more Oregonians
- Flexibility to achieve goals while working with the Oregon Public Utility Commission



New renewable portfolio standards

Current Renewable Portfolio Standard

Portland General Electric

Additional Renewable Resources

- PGE's 2009 Integrated Resource Plan addressed procurement of renewable resources to meet the 2015 requirement of Oregon's Renewable Portfolio Standard (RPS). To help meet this standard PGE built Tucannon River Wind Farm, a 267 megawatt, 116 turbine wind resource located in southeastern Washington.

	2011	2015	2020	2025	2030	2035	2040
RPS	5%	15%	20%	27%	35%	45%	50%

- Renewable Portfolio Standard qualifying resources supplied approximately 10% of PGE's retail load in 2012, 2013, & 2014, and 15% of retail load in 2015.

Renewable Adjustment Clause (RAC)

- Renewable resources can be tracked into prices, through an automatic adjustment clause, without a general rate case. A filing must be made to the OPUC by the sooner of the online date or April 1 in order to be included in prices the following January 1. Costs are deferred from the online date until inclusion in prices and are then recovered through an amortization methodology.

Executing on New Generation

Portland General Electric

Tucannon River Wind Farm

Capacity: 267 MW

In-service date: Dec. 2014

Project cost: $525 M

On time
On budget

Port Westward Unit 2

Capacity: 220 MW

Fuel: Natural Gas
Reciprocating Engines

In-service date: Dec. 2014

Project cost: $311 M

Decoupling Mechanism

The decoupling mechanism is intended to allow recovery of margin lost due to a reduction in sales of electricity resulting from customers' energy efficiency and conservation efforts.

This includes a Sales Normalization Adjustment (SNA) mechanism for residential and small nonresidential customers (≤ 30 kW) and a Lost Revenue Recovery Adjustment (LRRA), for large nonresidential customers (between 31 kW and 1 MWa).

- The SNA is based on the difference between actual, weather-adjusted usage per customer and that projected in PGE's 2015 general rate case. The SNA mechanism applies to approximately 61% of 2015 base revenues.
- The LRRA is based on the difference between actual energy-efficiency savings (as reported by the ETO) and those incorporated in the applicable load forecast. The LRRA mechanism applies to approximately 26% of 2015 base revenues.

In PGE's 2016, PGE and parties stipulated to the extension of the decoupling mechanism for three years, through the end of 2019. In addition, the use-per-customer baseline was adjusted for new connects with lower energy usage.

Recent Decoupling Results

(in millions)	2014	2015	YTD Q3 2016
Sales Normalization Adjustment	$(6.6)	$(6.9)	$3.8
Lost Revenue Recovery Adjustment	$1.4	$(1.9)	$0.0
Total adjustment	**$(5.2)**	**$(8.8)**	**$3.8**

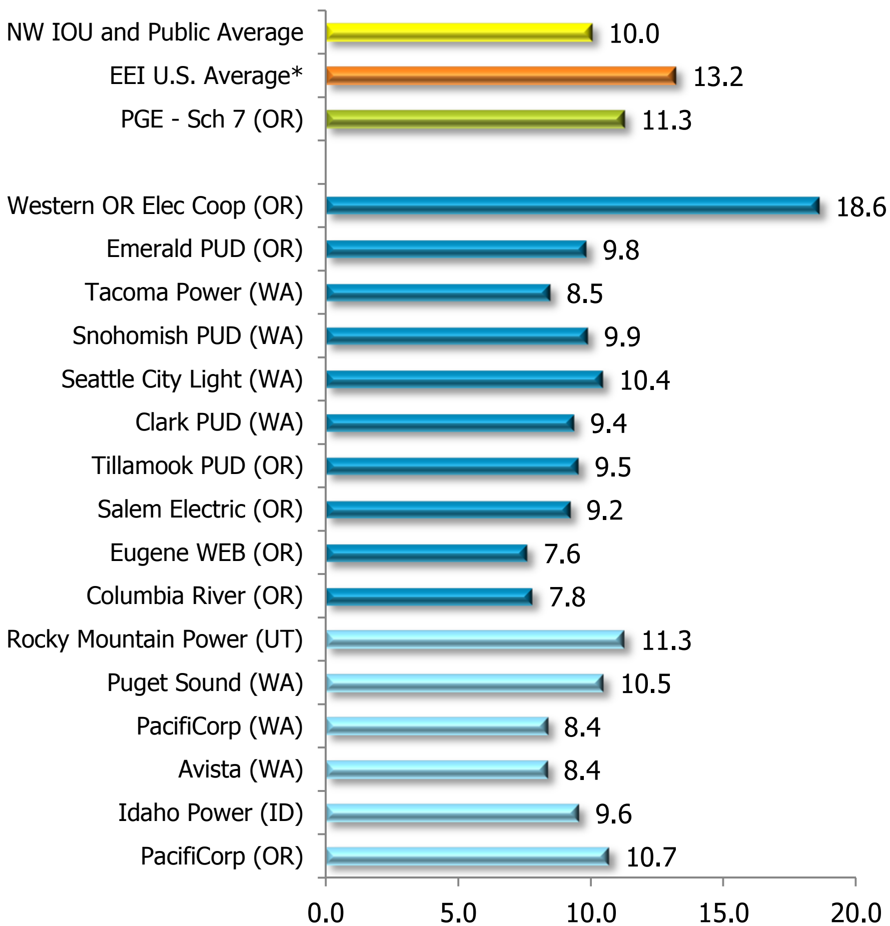
Note: refund = (negative) / collection = positive

Average Retail Price Comparison

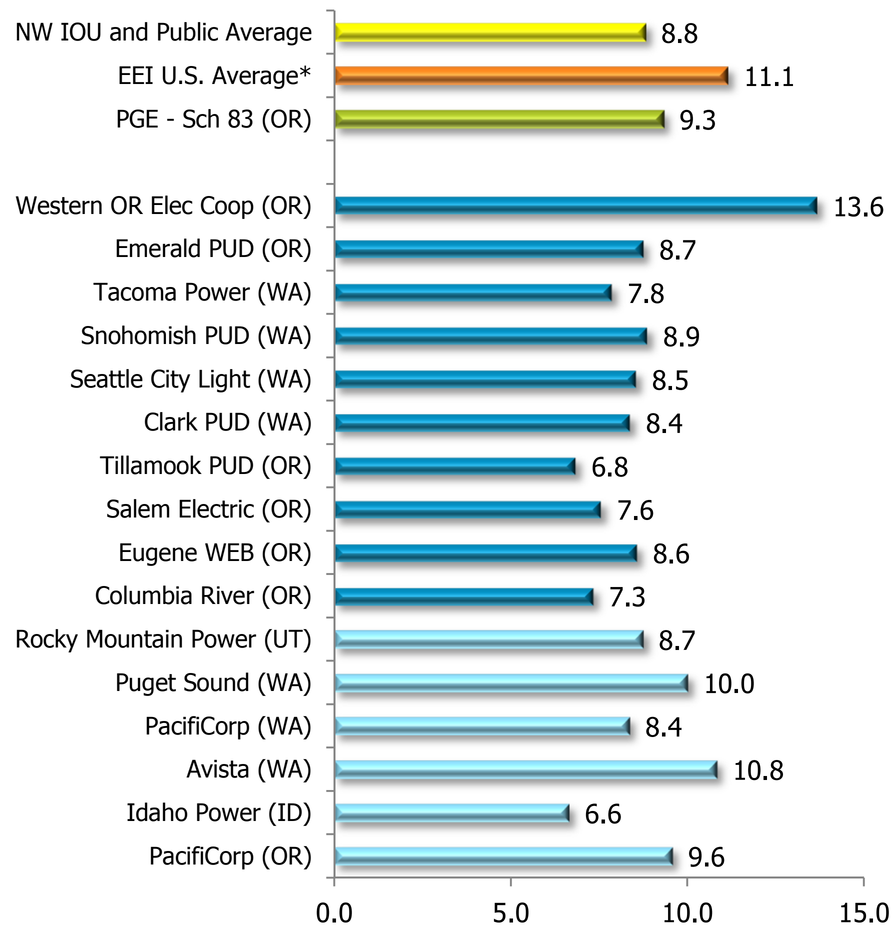
Residential and Commercial – Winter 2016

Portland General Electric

Residential Electric Service Costs
Northwestern Investor-Owned and Public Utilities
1,000 kWh per Month
(cents per kWh)



Commercial Electric Service Prices
Northwestern Investor-Owned and Public Utilities
40 kW Demand - 14,000 kWh per Month
(cents per kWh)



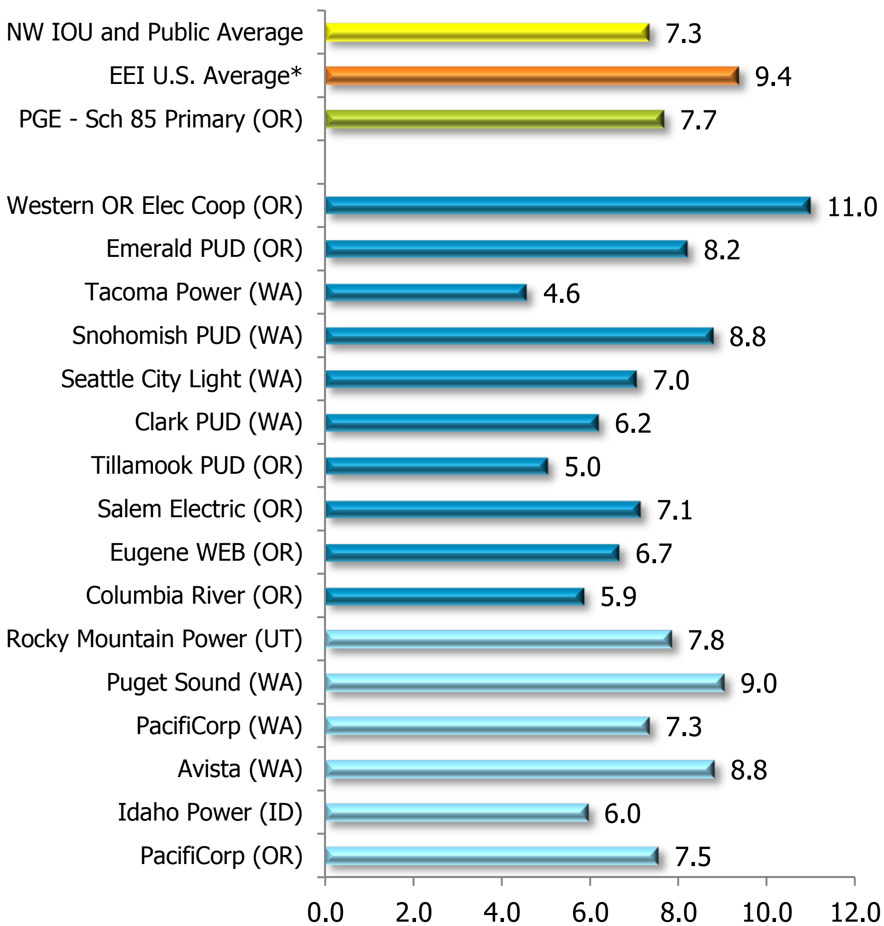
* This average is based on Investor-owned utilities only.

Average Retail Price Comparison

Small and Large Industrial – Winter 2016

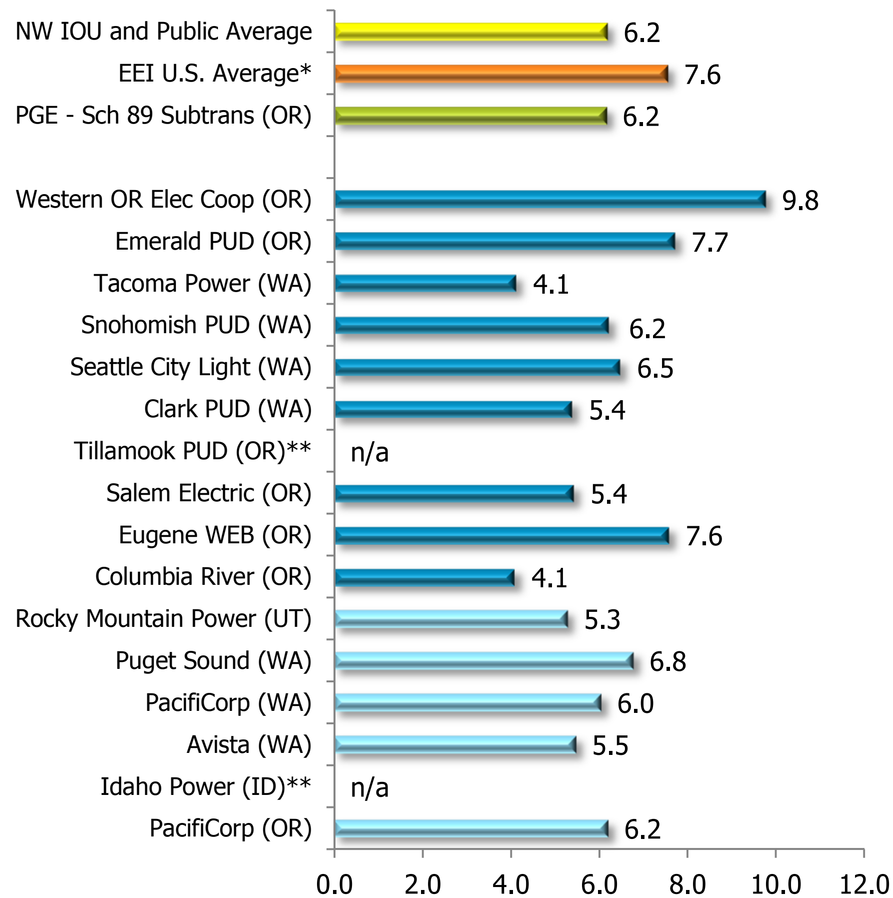
Small Industrial Electric Service Prices Northwestern Investor-Owned and Public Utilities

1,000 kW Demand - 400,000 kWh per Month, Primary Voltage
(cents per kWh)



Large Industrial Electric Service Prices Northwestern Investor-Owned and Public Utilities

50,000 kW Demand - 32,500,000 kWh per Month, Subtransmission Voltage
(cents per kWh)



* This average is based on Investor-owned utilities only.
** Idaho Power does not report a price to EEI for large industrial customers at this usage and demand level. Tillamook PUD does not offer a large general service tariff on their web site.

OG&E's SmartHours: from Pilot to Program

Kelly Marrin and Jessica Bryant

Spring WLRA, Anaheim CA

Agenda

- Timeline and Pilot background
- Rates and Technology
- Marketing
- Impacts
- Secrets to success
- Lessons learned

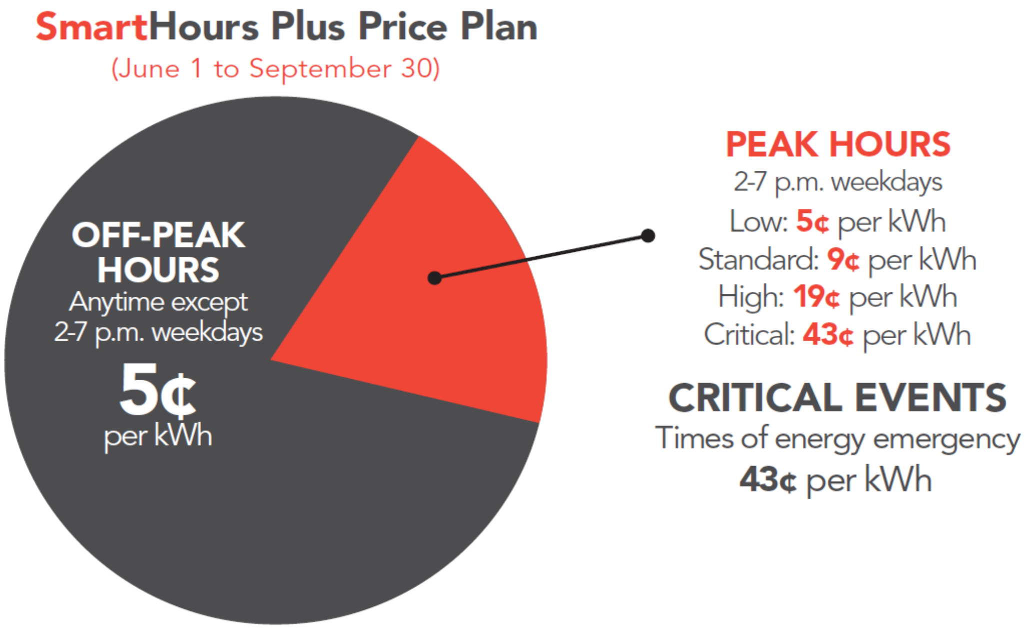
SmartHours Timeline

2010 Study	2011 Study	Pilot	2013	2014	2015

• 3,000 Customers
• Reduced Peak
• Segment Results
• Acceptance
  • Technology
  • Dynamic Pricing
	• 3,000 Customers
	• Dynamic Segmentation
	• Commercial Results
	• Critical Price Results
		• 43K Enrollments
		• 24k PCTs
		• Implement Dynamic Segmentation
			• 47k Enrollments
			• 23k PCTs
			• Enrollment open to all customers
				• 44k Enrollments
				• 27k PCTs
				• Commercial Load Disaggregation
				• Integrate Energy Efficiency
					• 26k Enrollments
					• 15k PCTs
					• 147 MW
					• 15% Churn
					  • 2% opt out
					• Target high value commercial customers

<u>As of September 2016</u>
Enrollments: 127k
Thermostats: 120k
MW 156

SmartHours Rate Variable Peak Pricing



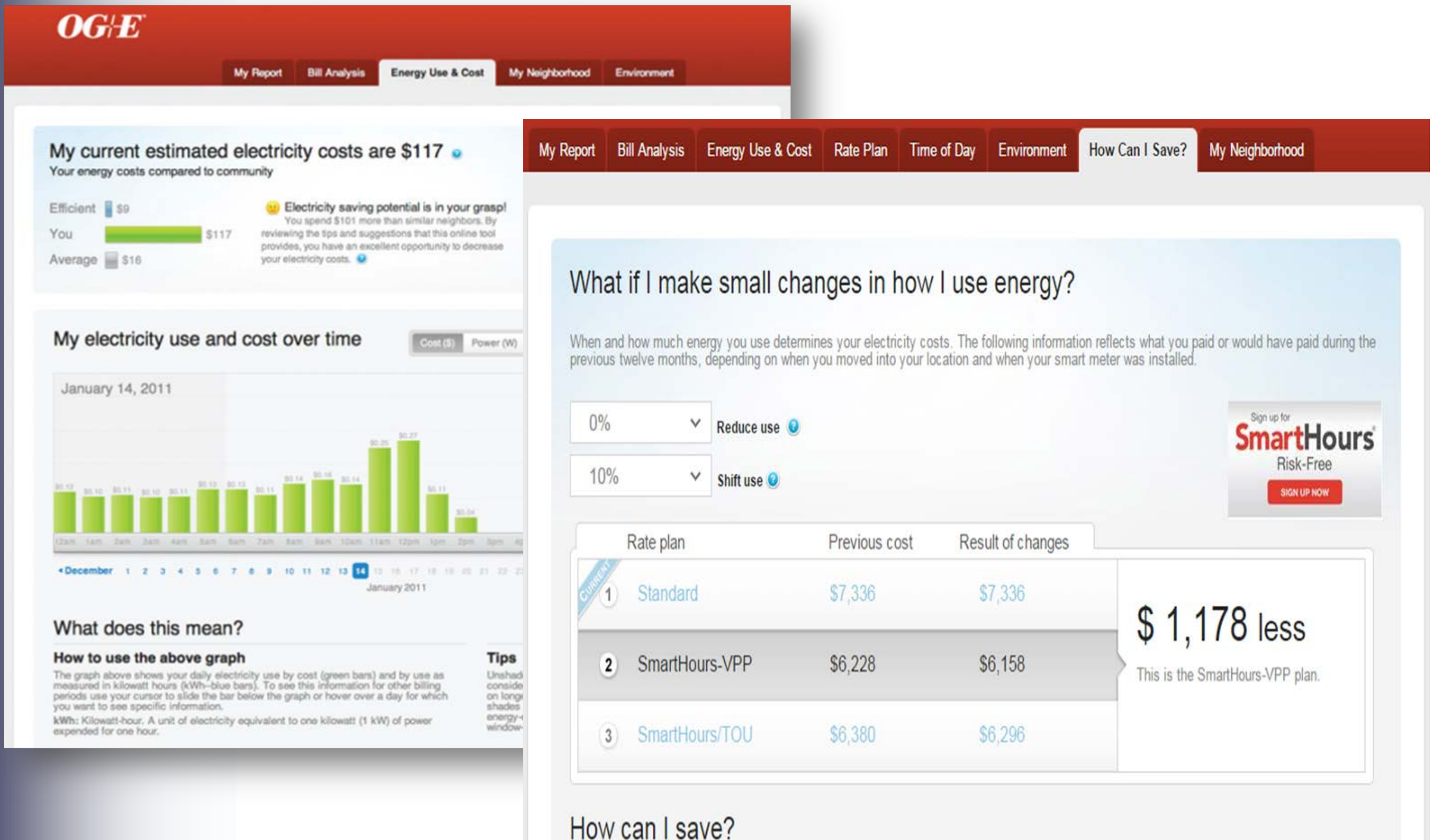
- Two period TOU with four potential on-peak prices
- Critical events can also be called with 2 hours notice at any time
- Residential and Commercial Customers have the same structure, but slightly different prices
- In 2015 there were: 9 low weekdays, 27 standard days, 42 high days, 3 critical days, and 7 critical events

Technology – PCTs

- **OG&E currently has two different thermostats in the field**
  - Thermostats are provided to participants at no cost
  - Started with the Energate thermostats in 2012 and 2013
  - In 2014 made the switch to Carrier thermostats
- The Carrier thermostats had several advantages
  - Sexier and cheaper
  - Fewer maintenance issues and complaints
  - Better customer feedback
  - Programming is more intuitive and customizable with individual setbacks for each prices vs. a gauge type setting on the Energate

AEG
Applied Energy Group

Technology – myOGEPower.com



Marketing

Target High Value Customers

Residential & Commercial Strategies

Residential – High shifting ability based on consumption

Commercial – Building Type, schools and churches

OG&E works with a third party to find the right cadence of emails, mailers, and phone calls

Reach out to those who moved to get them back on the program

Touch Everyone

Highlight potential savings with tools and technology

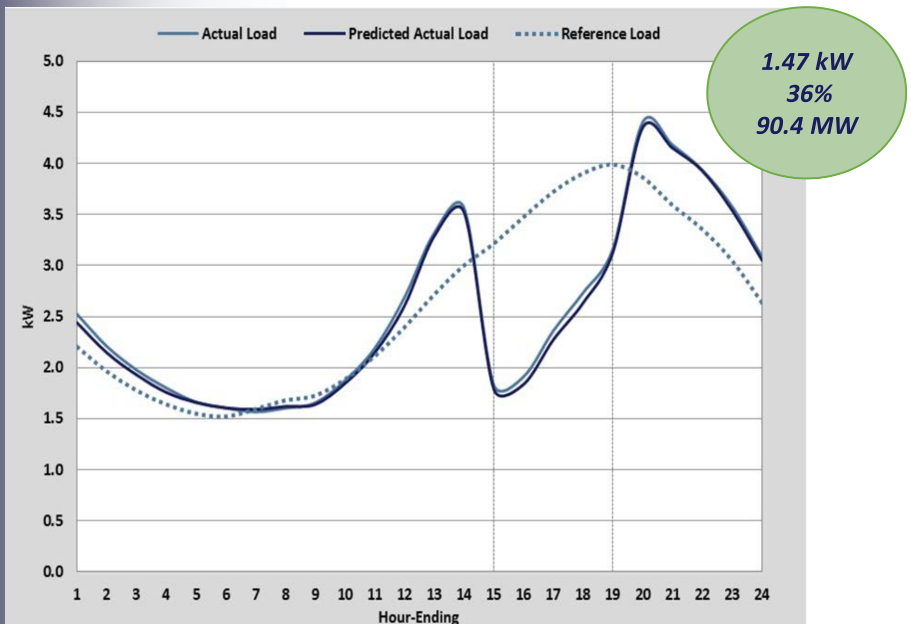
Leverage the Data

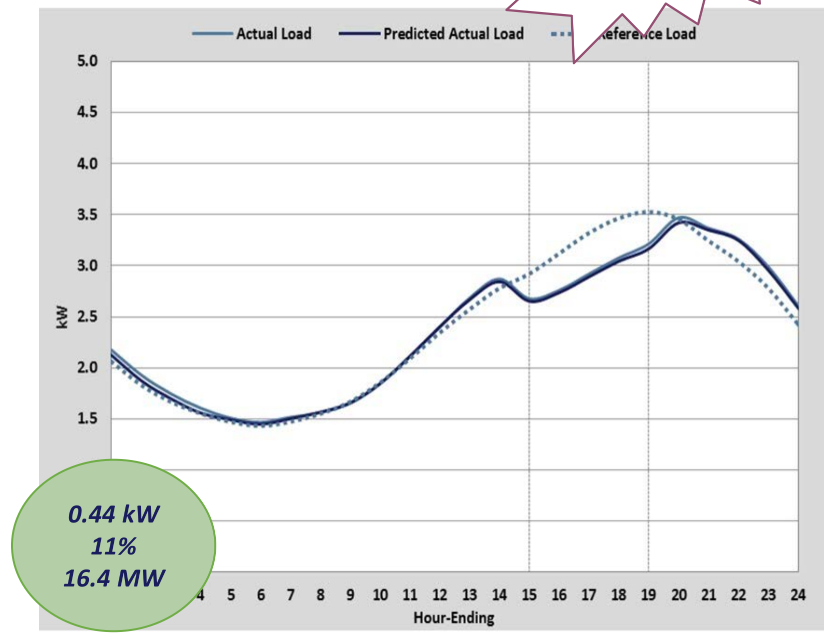
Residential and commercial studies to identify “responders”

In house models that identify customers with high probability to enroll, commercial segmentation analysis

Need to add commercial

2015 Per Customer Impacts





Change to graph for and include commercial

SmartHours Impacts Over Time

Program	Price Day	Impacts 2015 Hourly Models	Impacts 2014 Hourly Models	Impacts 2013 Hourly Models	Impacts 2012 Hourly Models	Impacts 2011 Pilot
SmartHours Plus	Low	24%	27%	25%	4%	1%
	Standard	28%	27%	31%	25%	18%
	High	33%	33%	35%	30%	20%
	Critical	33%	-	-	29%	23%
	CPE	36%	36%	38%	34%	29%
SmarHours VPP	Low	11%	13%	20%	1%	9%
	Standard	10%	12%	18%	9%	13%
	High	11%	10%	14%	11%	15%
	Critical	10%	-	-	10%	14%
	CPE	11%	11%	12%	14%	13%

Maybe reformat with smart art

Do Customers Save Money?

Residential	Average Savings	% who saved
SmartHours	$152.32	99%
Commercial		
SmartHours	$302.48	88%

- Customers who used a SmartTemp Thermostat saved 46% more than customers without the thermostat
- 40% of the districts in the state have signed up for SmartHours saving them over $2 million dollars so far!

Maybe reformat with smart art

Why does it work?

Great Rate Design

Thorough development and testing

Education

Marketing

Buy In

Reliable Devices

Great Partners

Customer Support

Constant Improvement

Lessons Learned

- Not all customers are created equal
- Having trusted partnerships with installers is paramount
- Company-wide buy in
- Engage with IT during testing and implementation
- Highlight savings for customers
- Communicate, educate, provide feedback
- Don’t give up!

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