Oregon

Kate Brown, Governor

Public Utility Commission
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November 1, 2018

Oregon State Legislature
900 Court St NE
Salem, OR 97301

Dear Honorable Members:

The Public Utility Commission of Oregon respectfully submits the enclosed report "Greenhouse Gas Reduction Goal Rate Impact Report: Report to the 2019 Oregon Legislature," in compliance with the requirements of SB 101 (2009). The report demonstrates the success of complementary policies and industry evolution to reduce the electric sector's greenhouse gas (GHG) intensity since enactment of SB 101 in 2009.

SB 101 required the PUC, on or before November 1 of each even-numbered year, to report the estimated rate impacts of the regulated electric and gas utilities meeting two non-binding greenhouse gas (GHG) emission goals by 2020:

- Goal #1: 10 percent below 1990 emission levels, which is a non-binding state goal set by the Oregon Legislature in HB 3543 (2007); and
- Goal #2: 15 percent below 2005 emission levels (Goal #2), which was identified in 2007 through Oregon's participation in the Western Climate Initiative.

In this, the PUC's [fifth] SB 101 report, estimated costs per utility customer to meet the identified GHG reduction goals have decreased from estimates in prior PUC reports. Notably, investor-owned electric utilities are largely on track to meet the goals with business-as-usual actions (with one exception, where incremental action is still required to meet the goal but the cost of incremental action is significantly lower).

The PUC recognizes that Oregon's GHG policy landscape has changed significantly since 2009. Today, the 2018 Interim Joint Committee on Carbon Reduction and the Governor's Carbon Policy Office are designing a new, binding carbon policy proposal for consideration by the 2019 Oregon Legislature. To help prevent any confusion between the PUC's legacy SB 101 report and today's policy discussions, I highlight two points.

First, if new legislative policy were to apply binding GHG policy to Oregon's investor-owned utilities, the PUC would use its integrated resource planning (IRP) process and other tools to test multiple viable pathways to achieve compliance at least cost and least risk to Oregon utility customers. In contrast, to prepare the SB 101 report, the PUC merely reviews for reasonableness the estimated cost of the GHG reduction pathway or pathways each utility provides in relationship to planned actions through their existing IRPs.

Second, SB 101 did not require reporting on the GHG emissions from end use of natural gas. Instead, the reporting requirement was limited to emissions caused by leakage from the Oregon natural gas utilities' distribution systems and gas equipment. Therefore, the SB 101 report identifies purchase of a small number of carbon offsets as the only incremental GHG reduction action for each gas utility.

If the Legislature enacts new GHG policy for the state of Oregon in 2019, the PUC encourages the Legislature to consider whether it will remain worthwhile for the PUC to submit a sixth SB 101 report in 2020.

Please do not hesitate to contact Julie Peacock at julie.peacock@state.or.us or 503-378-3623 with any questions about the report.

Sincerely,

Megan Decker
Commission Chair

Oregon Public Utility Commission

Greenhouse Gas Reduction Goal Rate Impact Report

Report to the 2019 Oregon Legislature

2018

Table of Contents

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Executive Summary

In 2009, the Oregon Legislature enacted Senate Bill 101 (SB 101), which requires the Oregon Public Utility Commission (PUC) to report the estimated rate impacts of the regulated, investor-owned electric and gas utilities achieving two greenhouse gas (GHG) emission targets by 2020:

- Goal #1 - 10 percent below 1990 emission levels.
- Goal #2 - 15 percent below 2005 emission levels.

The goals are not binding on the utilities, so customers bear no actual costs. The PUC reports are due to the Legislature before November 1 of each even-numbered year.

Electric Company Reductions and Rate Impacts

Burning coal and natural gas to produce electricity emits GHGs. Each of the three electric investor-owned utilities (IOUs) that the PUC regulates, Portland General Electric Company (PGE), PacifiCorp, and Idaho Power Company (Idaho Power), emit GHGs to serve their customers with electricity. SB 101 requires IOUs to identify actions needed to achieve the GHG reduction goals noted above, and then estimate the incremental impact of those actions on customer costs. These emissions reductions and related costs are summarized below in Table ES1. Only for PGE would action beyond business-as-usual be necessary to reach the GHG goals.

Table ES1: Electric Utility Emissions Relative to GHG Reduction Goals

		PGE	PAC	IPC
Total System Emissions (metric tons CO_2)				
Goal #1	1990 Baseline	4,565,736	49,877,778	7,598,952
	10% reduction	4,109,162	44,890,000	8,067,721
Goal #2	2005 Baseline	8,691,704	60,941,176	6,839,057
	15% reduction	7,387,948	51,800,000	6,857,563
Business as Usual Emissions	2020 Estimate	**5,440,188**	**37,432,000**	**3,581,342**
Emissions with Incremental GHG Actions To Meet Goal(s)	2021 Estimate[1]	**3,680,629**	N/A	N/A
Estimated Cost to Achieve Goal Divided by Number of Customers				
Goal #1		$174	$0	$0
Goal #2		$0	$0	$0

Portland General Electric – PGE's current least-cost, least-risk resource plan is on track to meet Goal #2 – 15 percent below 2005 emissions level – in 2020. Accordingly, there is no estimated rate impact to meet this target.

However, meeting Goal #1 – 10 percent below 1990 emissions level – is more challenging for PGE. This is because the Trojan nuclear plant and contracts with Columbia River hydroelectric facilities contributed a significant amount of zero-emitting energy to PGE's electricity supply in 1990. When these resources were no longer a part of PGE's resource mix, its GHG emissions rose.

[1] SB 101 requests a report on the estimated rate impacts of meeting the non-binding goals by 2020. However, PGE is completing significant cost-effective GHG mitigation actions in 2020, which will significantly reduce its GHG estimate for 2021. Rather than estimating rate impacts of meeting the GHG goals by 2020, the PUC has allowed PGE to estimate rate impacts based on meeting either goal by 2021, as this provides the most accurate estimate of the incremental cost of additional GHG reductions.

PGE's current resource plan includes two significant actions by the end of 2020 that will reduce GHGs: the retirement of the Boardman coal plant and the addition of new renewable resources through a pending request for proposals. Even with these business-as-usual actions lowering PGE's 2021 emissions, however, PGE will not meet Goal #1 in 2021. To estimate the impact on ratepayers of meeting Goal #1 in 2021, PGE assumes it would curtail coal-fired operations at units 3 and 4 of the Colstrip coal plant and replace this higher-emitting generation with market purchases. These actions would increase estimated costs by a total of $159 million in 2021. Spreading this $159 million equally over PGE's total number of customers produces a cost of $174 per customer in 2021. This is a significantly lower estimated cost than was presented in the 2016 report.

PacifiCorp – PacifiCorp's current least-cost, least-risk resource plan achieves emissions levels lower than both goals in 2020. Accordingly, there is no rate impact associated with meeting either goal. The emission reduction goals are met largely through the dispatch of existing and new resources along with incremental acquisition of demand-side management (DSM) resources, e.g. energy efficiency. This eliminates the estimated rate impact that was presented in the 2016 report. This reduction is in large part due to the business-as-usual reduction in reliance on the company's coal units.

Idaho Power – Idaho Power's current least-cost, least-risk resource plan achieves emission levels lower than both goals in 2020. Because no additional actions are necessary, Idaho Power estimates no rate impact. Significant increases in purchases of low-carbon electricity from independent power producers on Idaho Power's system contributed to meeting the goals.

Natural Gas Company Reductions and Rate Impacts

Avista Utilities (Avista), Cascade Natural Gas Corporation (Cascade or CNG), and Northwest Natural Gas Company (NW Natural) are investor-owned local distribution companies (LDCs) that serve Oregon's natural gas customers.[2] The emissions associated with the end-use of the natural gas have not been credited to the LDCs in this report, nor have the upstream emissions associated with the production of natural gas utilized by these companies.[3] SB 101 only included the small amount of greenhouse gases directly emitted through these companies' distribution system and gas equipment via leaks.
NW Natural, Cascade, and Avista each identified the purchase of carbon offsets as the actions they would take to achieve the emission reduction targets with minimal cost impacts. These emissions reductions and related estimated costs are summarized below in Table ES2.

Table ES2: Local Distribution Company Emissions Relative to GHG Reduction Goals

		NWN	CNG	Avista
Total System Emissions (metric tons CO_2e)				
Goal #1	1990 Baseline	90,721	7,797	9,557
	10% reduction	81,649	7,017	8,601
Goal #2	2005 Baseline	90,721	7,797	9,557
	15% reduction	77,113	6,627	8,123
Business as Usual Emissions	2020 Estimate	**77,658**	**8,164**	**9,842**
Estimated Cost to Achieve Goal Divided by Number of Customers				
Goal #1		$0.00	$0.25	$0.22
Goal #2		$0.01	$0.34	$0.31

[2] Each of the three LDCs have service territory outside of the State. Additionally, Avista, which is the process of being acquired by Hydro One, provides electric service in both Washington and Idaho.
[3] For example, a residential customer heating their home with natural gas is responsible for the associated GHG emissions, rather than the LDC which supplied the natural gas.

Introduction

In 2004, the Governor's Advisory Group on Global Warming recommended that greenhouse gas emission targets should be codified. At that time, the United Nations Intergovernmental Panel on Climate Change estimated that global carbon dioxide emissions needed to be reduced by 60-80 percent below 1990 levels to avoid dangerous interference with climate systems. In 2007, the Oregon Legislature passed HB 3543, which made the following findings:

- Global warming poses a serious threat to the economic well-being, public health, natural resources, and environment of Oregon.
- Oregon relies on snowpack for summer stream flows to provide energy, municipal water, watershed health, and irrigation. Reduced snow pack, changes in the timing of stream flows, extreme or unusual weather events, rising sea levels, increased occurrences of vector-borne diseases, and impacts on forest health could significantly impact the economy, environment, and quality of life in Oregon.
- Oregon forests play a significant role in sequestering atmospheric carbon, and losing this potential to sequester carbon will have significant negative effect on the reduced carbon levels in the atmosphere.
- Oregon has been a national leader in energy conservation and environmental stewardship.

Accordingly, the bill established three non-binding greenhouse gas emission reduction goals for the state:

a) By 2010, arrest the growth of Oregon's greenhouse gas emissions and begin to reduce greenhouse gas emissions.
b) By 2020, achieve greenhouse gas levels that are 10 percent below 1990 levels.
c) By 2050, achieve greenhouse gas levels that are at least 75 percent below 1990 levels.

In 2009, the Legislature passed SB 101, which among other things requires the PUC to report to the Legislature before November 1 of each even numbered year on the estimated rate impacts of two goals:

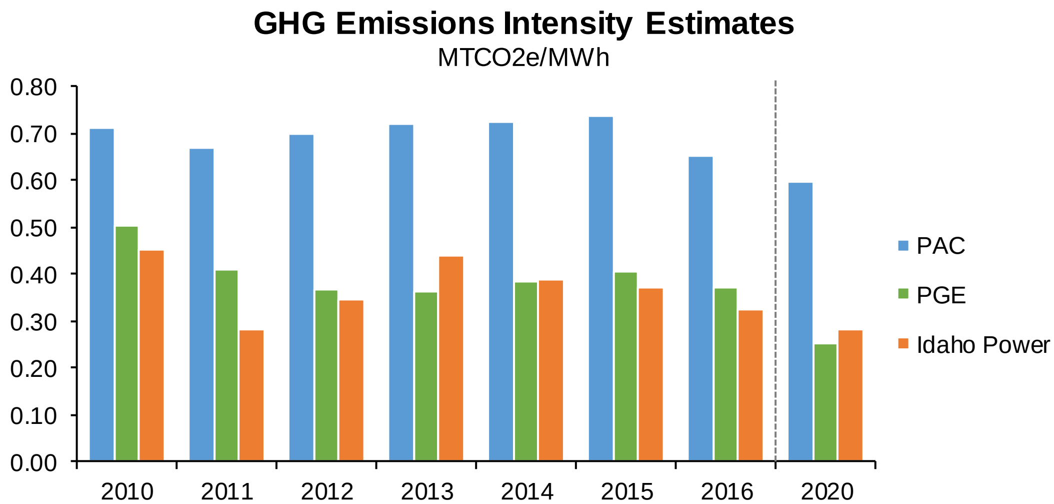
- 10 percent below 1990 levels (goal b) from HB 3545, referred to hereafter as Goal #1,
- 15 percent below 2005 levels[4], referred to hereafter as Goal #2.

Critical to meeting these economy-wide goals is the emission intensity of investor owned utilities (IOUs) in the state. In 2015, natural gas and electricity together accounted for over 40 percent of Oregon emissions.[5] Figure 1 below displays the three electric IOU's GHG intensity since 2010. These estimates are collected by the Oregon Department of Environmental Quality (DEQ) from the generation of electricity provided to end-users in Oregon. Intensity estimates for 2016 are projected by DEQ while the

[4] This goal comes from the Western Climate Initiative, created by governor Kulongoski along with the governors of Arizona, California, New Mexico, and Washington in 2007.
[5] Oregon Department of Environmental Quality, State Greenhouse Gas Emissions 1990-2015 Inventory.

2020 rates are estimated using the company's reported projections of emissions and electricity provided to customers included in the following sections of this report.

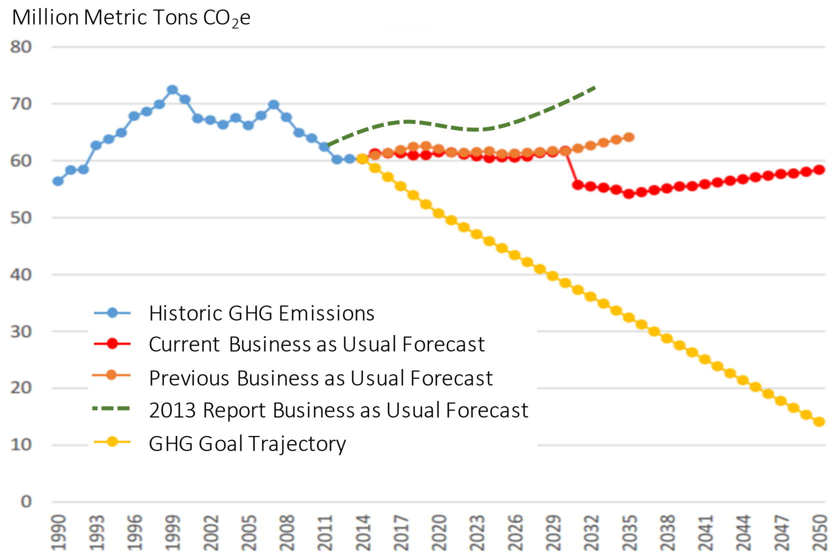
Figure 1: GHG Intensity Estimates for the Electric Utilities



Sources: 2010-2016 Oregon Department of Environmental Quality, 2016 data is preliminary. 2020 estimated based on electric utility initiaitves to meet the emission reduction goals

Figure 2 below displays Oregon's historic greenhouse gas emissions trends from all emission sources in the state, business as usual (BAU) forecasts through time, and a straight-line trajectory to the 2020 goal. It is clear from the graphic that, since the development of the 2004 BAU forecast, Oregon has made significant reductions in its greenhouse gas emissions intensity. However, current actions are still less than what is needed to meet the 2020 emission reduction goals set by the state. Additionally, though each BAU forecast has adjusted downward over time, overall the projections into the future still hold emissions at fairly constant levels going forward. Even the current BAU forecast conducted in 2017 does not expect emissions to decrease much during the forecast period. Additional action is needed to preserve the reductions established since 2005 and meet the state's emission reduction goals.

Figure 2: State Greenhouse Gas Emissions and Projections



Source: 2017 Oregon Global Warming Commission Report

2018 Electricity Greenhouse Gas Reduction Goal

Portland General Electric

Utility Background

Portland General Electric (PGE) has provided electricity to customers in the northern Willamette Valley since 1889. Today, PGE serves customers within a 4,000-square mile service territory, including 51 Oregon cities. PGE distributes electricity to customers in parts of Multnomah, Clackamas, Marion, Yamhill, Washington, and Polk counties, which represent roughly 44 percent of the population of Oregon. PGE currently serves more than 874,000 retail customers at an average residential rate of 11.42₵ per kilowatt hour, which is below the May 2018 U.S. average of 13.15₵ per kilowatt hour.[6]

PGE's current resource portfolio remains reliant on fossil fuels. Its five natural gas-burning plants produce an average of about 36 percent PGE's electricity, and its ownership portion of the Boardman and Colstrip coal-fired plants produce 28 percent on average. GHG-free resources, including wind, solar, and hydro, represent a combined 42 percent of average electric generation deliveries.[7]

In order to estimate the impact of meeting Goals #1 and #2, an understanding of business-as-usual emissions, absent any additional GHG mitigation, is needed. Each IOU creates an integrated resource plan (IRP) to forecast a 20 year plan based on a number of scenarios and uncertainties. An output of this plan is a load-resource balance, which projects which resources will be used to meet the projected load in each year. Table 1 displays the estimated load-resource balance projected for 2020 in the latest PGE IRP (2016), as well as that from its previous IRP and the difference between the two.

Table 1: PGE Energy Portfolio IRP Comparison (System-Wide)

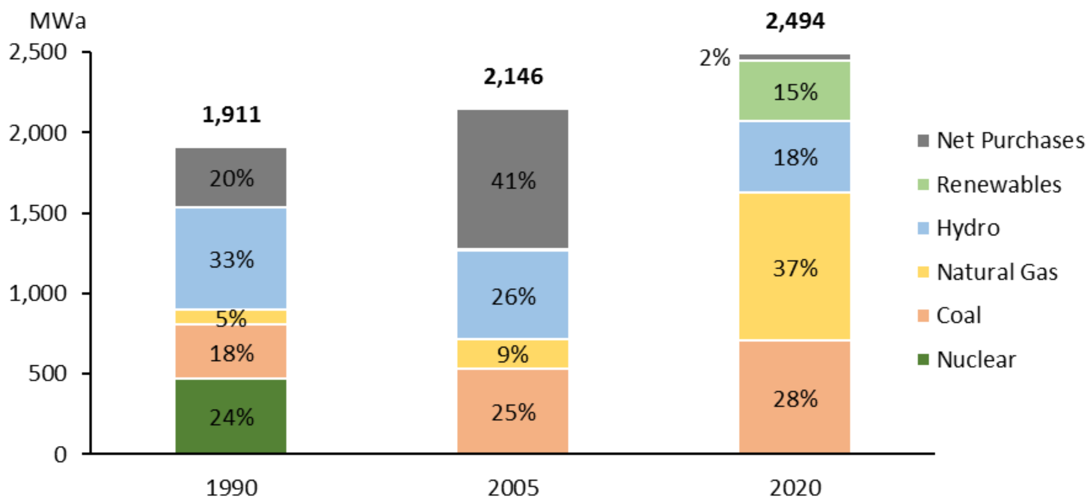
2020 Total System – Load / Resource Balance (MWh)			
	(A)	(B)	(B - A)
Generation Type	**2013 IRP Energy Sources**	**2016 IRP Energy Sources**	**Difference**
Hydro	2,748,750	3,952,800	1,204,050
Coal	4,624,220	6,192,720	1,568,500
Natural Gas	8,938,862	8,081,280	(857,582)
Renewables	2,223,254	3,250,080	1,026,826
Net Market Purchases[8]	703,985	430,416	(273,569)
Resources Total	**19,239,071**	**21,907,296**	**2,668,225**

[6] EIA Average Price of Electricity to Ultimate Customers by End-Use Sector: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
[7] As part of mandatory GHG reporting for the state emissions inventory, the Oregon Department of Environmental Quality includes emissions associated with market purchases or generation that is accounted for in utility electricity rates, regardless of renewable energy certificate (REC) ownership.
[8] These include PPAs and other contracts

Additionally, emissions from the baseline years set in the climate goals are necessary to evaluate each goal's target emissions. PGE's baseline emissions in 1990 and 2005 are calculated based on the historic megawatt hours (MWh) used to serve load. Figure 3 displays the energy mix used to meet load in both 1990 and 2005, as well as resources projected in 2020.

PGE's resource portfolio has changed dramatically between 1990 and 2018. In 1993, PGE closed Trojan Nuclear Plant, 20 years before its planned retirement date. PGE also lost access to a significant portion of mid-Columbia hydroelectric power contracts. The loss of these non-emitting generation resources is compounded as retail loads have increased by more than 25 percent during the same period.

Figure 3: PGE Energy Portfolio



SB 101 requests a report on the estimated rate impacts of meeting the non-binding goals by 2020. However, PGE is completing significant cost-effective GHG mitigation actions in 2020, reducing the additional action needed to meet the goals and thus the estimated additional cost. By 2021, PGE's decision to close the Boardman coal plant and develop 100 average megawatts (MWa) of renewables will result in lower emissions, assuming these renewables displace some natural gas generation and allow for the curtailment of Colstrip 3 and 4. Rather than estimating rate impacts by 2020, the PUC has allowed PGE to estimate rate impacts based on meeting the goals by 2021, as this provides the most accurate estimate of the incremental cost of additional GHG reductions.

Emissions Reduction Report Information

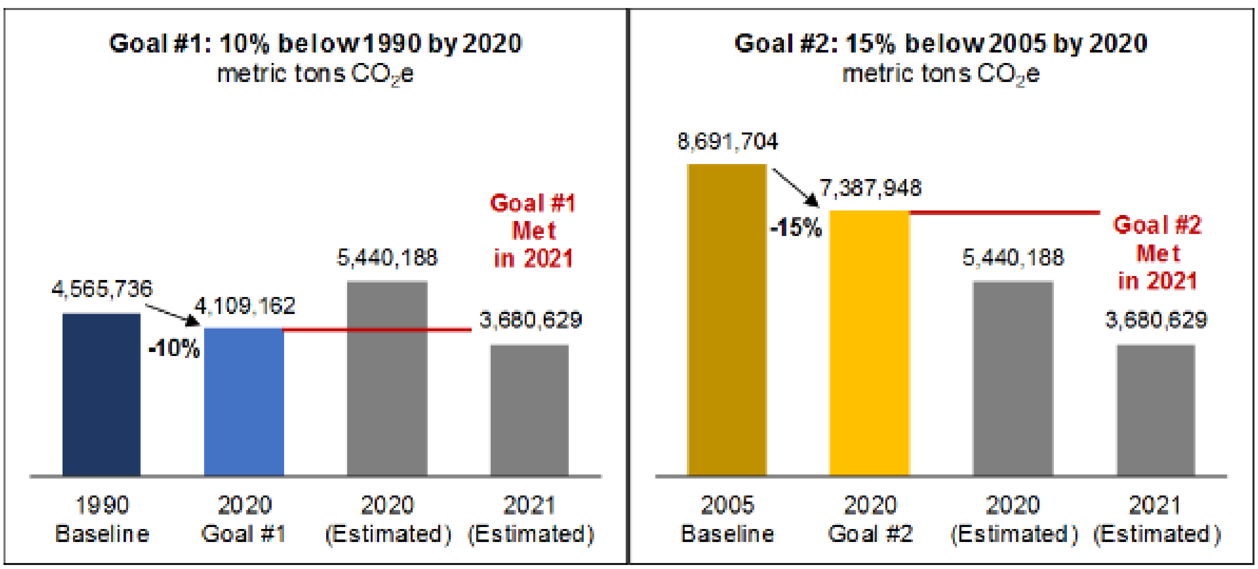
Under business-as-usual practices in 2020, PGE will meet Goal #2 – 15 percent below 2005 emissions (see Figure 4). In fact, PGE's current least-cost resource mix will enable the company to emit 26 percent less than Goal #2 requires. Some of this decrease is due to the portfolio of existing technology resources modeled and acknowledged in the 2016 IRP and 2016 IRP Update. By 2021, business-as-usual resource actions will further reduce GHG emissions due to the retirement of the Boardman coal plant and the addition of renewable resources.

However, these actions are not enough to meet Goal #1 - 10 percent below 1990 emissions – in 2021. To meet Goal #1, PGE would have to further reduce emissions from expected 2021 levels by roughly 18 percent through incremental GHG actions. PGE's cost estimate for incremental action to meet Goal #1 in 2021 is based on curtailing coal-fired operations at Colstrip units 3 and 4 and replacing that energy with market purchases.

Table 2: PGE Emissions Comparison Table

Total System Emissions (metric tons CO_2)		PGE
Goal #1	1990 Baseline	4,565,736
	10% reduction	4,109,162
Goal #2	2005 Baseline	8,691,704
	15% reduction	7,387,948
Business-as-Usual Emissions	2020 Estimate	**5,440,188**
	2021 Estimate	**4,992,953**
Emissions with Incremental GHG Actions to Meet Goal(s)	2021 Estimate	**3,680,629**

Figure 4: PGE Emissions Comparison



Modeling Approach

Goal #2 (15 percent below 2005 emissions) is met under business-as-usual actions by PGE, even when considering 2020 emissions before the closure of Boardman and the renewable request for proposals (RFP). Goal #1 (10 percent below 1990 emissions) is met by assuming PGE discontinues taking service from coal-fired operations at Colstrip on December 31, 2020. For rate impact estimation, the present value of fixed revenue requirements associated with the remaining unrecovered investment as of year-end 2019 is recovered in 2020. Resources are added to the model portfolios in 2019, 2020, and 2021. For electricity supplied through net market purchases, standard offer sales, and electricity service suppliers, PGE assumed a carbon intensity of 900 pounds per megawatt hour.

Consumer Rate Impacts

As noted above, to avoid counting cost-effective mitigation efforts which are already planned, the costs associated with achieving Goal #1 are estimated to begin in 2021. This does not allow for an "apples-to-apples" comparison across utilities. To comply with the GHG goals by January 1, 2020, PGE would need to find emissions-free replacement generation for year 2020, the costs of which are significant and are not reflected in Table 3. The 2021 costs are a better reflection of PGE's incremental costs.

Table 3: Cost Impact to PGE Customers to Meet 2020 Goal #1

Relative to Preferred Portfolio							
	Incremental Revenue Requirement ($ millions)	**Cumulative Revenue Requirement ($ millions)**	**Total Customers**	**Incremental Dollars per Customer**	**Cumulative Dollars per Customer**	**Rate Impact (%)**	**Cumulative Rate Impact (%)**
2019	$0	$0	895,213	$0	$0	0.0%	0.0%
2020	$185	$185	905,958	$205	$205	9.4%	9.4%
2021	($26)	**$159**	916,749	($28)	**$174**	-1.3%	7.9%

As shown above in Table 3, the cumulative cost of incremental GHG actions required to meet Goal #1 are estimated to be $174 per customer. This is a reduction from the 2016 report, which estimated costs to be $791 per customer. This change is in large part due to the renewable request for proposals (RFP) as well as PGE's reduced reliance on Boardman, both of which reduce emissions in the company's business-as-usual baseline, requiring a smaller reduction in emissions.

It's important to note that it is questionable whether reducing production from Colstrip's units 3 and 4 is actionable given the company's current contract with other plant owners, and also uncertain whether sufficient market purchases would be available to replace Colstrip production.

Another important consideration in these projections is PGE's reliance on building and/or retiring generation assets. In its analysis, the company presented only two options to meet the stated GHG reduction goals: building a significant amount of renewables or an early termination of service from Colstrip units 3 and 4.

PacifiCorp

Utility Background

PacifiCorp (PAC) serves nearly 1.8 million customers across six states, with 580,492 customers in Oregon. In 1989, PacifiCorp merged with Utah Power & Light, and continues doing business as Pacific Power delivering electricity to customers in Oregon, Washington, and California, while Rocky Mountain Power delivers electricity to customers in Utah, Wyoming, and Idaho. The company owns 72 generating units, including 41 hydroelectric plants which supply 7 percent of their energy. Over 60 percent of PacifiCorp's supplied power is from coal-fired units.[9]

Figure 5: PacifiCorp Energy Portfolio

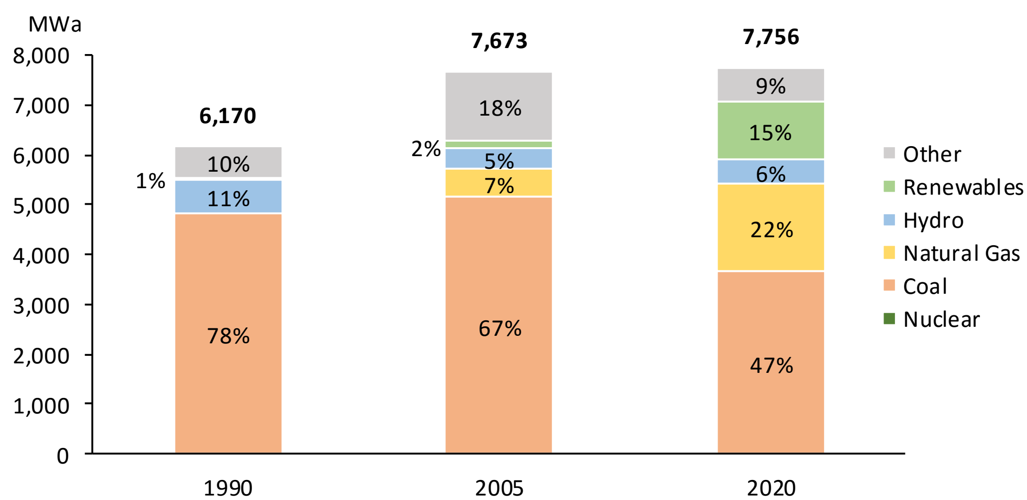


Table 4: PacifiCorp Energy Portfolio

2020 Total System – Load / Resource Balance (MWh)			
	(A)	(B)	(B - A)
Generation Type	**2015 IRP Energy Sources**	**2017 IRP Energy Sources**	**Difference**
Hydro	4,302,000	4,246,000	(56,000)
Coal	41,055,000	32,262,000	(8,793,000)
Natural Gas	12,893,000	15,253,000	2,361,000
Renewables	8,272,000	10,437,000	2,165,000
Existing Net Long-Term Purchases	1,544,000	1,781,000	228,000
Front Office Transactions	1,235,000	474,000	606,000
Other[10]	83,000	689,000	606,000
Class 1 DSM + Interruptibles	-	10,000	10,000
Class 2 DSM	4,160,000	2,913,000	(1,247,000)
Net System Balancing Sales	(7,671,000)	(5,513,000)	2,158,000
Resources Total[11]	**65,882,000**	**62,553,000**	**(3,329,000)**

[9] PacifiCorp facts: http://www.pacificorp.com/About_Us/Company_Overview/PC-FactSheet-Final_Web.pdf

[10] Other includes combined heat and power, distributed generation, and other resources.

[11] Includes Class 2 demand-side management (DSM) not included in the table.

To develop a portfolio that achieves targeted carbon dioxide emission reductions, PacifiCorp's capacity expansion optimization model, System Optimizer, was set up with hard annual carbon dioxide emissions caps. These caps constrain the model to solve for the least-cost resource expansion plan that does not exceed the physical carbon dioxide emission limits across PacifiCorp's multi-state system in each year of the simulation.

PacifiCorp initiated its analysis from its 2017 Integrated Resource Plan Update (2017 IRP Update). It is revised to develop a base portfolio for the purposes of this analysis, reflecting the most recent official forward price curve dated March 31, 2018 with the 2017 IRP Update portfolio re-optimized to account for the impact of updated market prices. Potential expansion resource options available in the current study are the same as those used in the development of the 2017 IRP Update. No retirements or conversion of coal units to operate as natural gas-fired facilities beyond those in the 2017 IRP Update are included in the analysis. Similarly, resources that are not currently commercially available or financially viable are not included in the resource portfolios during the 2018 through 2020 study period covered by this analysis.

Table 5: PacifiCorp Emissions Comparison Table

Total System Emissions (metric tons CO_2)		PAC
Goal #1	1990 Baseline	49,877,778
	10% reduction	44,890,000
Goal #2	2005 Baseline	60,941,176
	15% reduction	51,800,000
Business as Usual Emissions	2020 Estimate	**37,432,000**

Figure 6: PacifiCorp Emissions Comparison

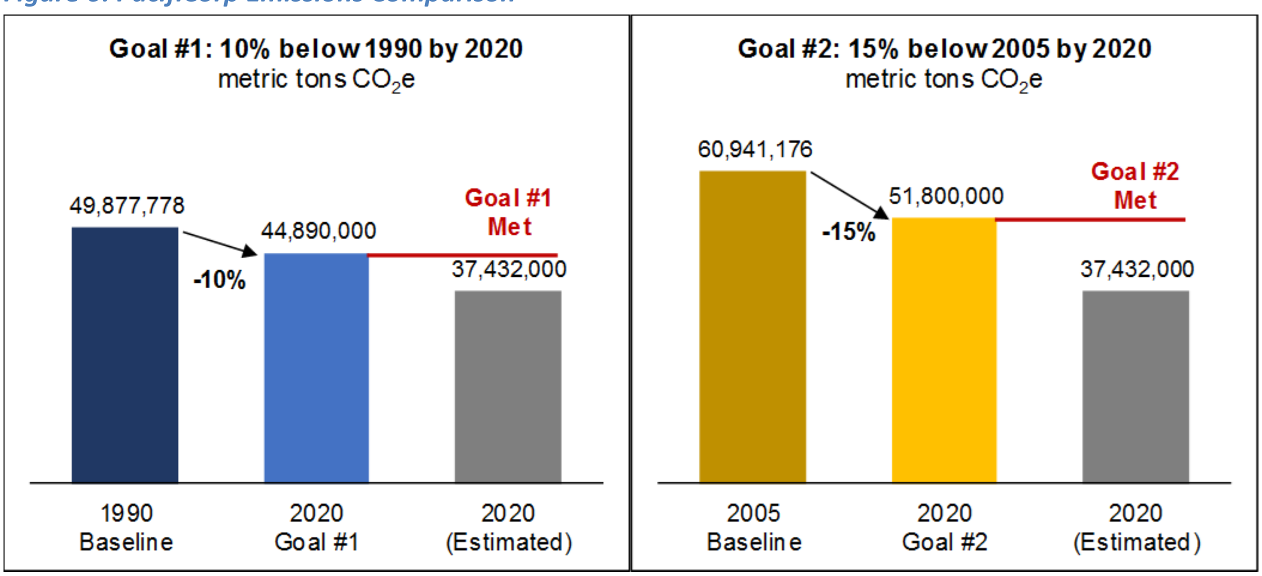


Figure 6 shows that PacifiCorp projected emissions across its system to be below both Goals #1 and #2. The emission reduction goals are met largely through the dispatch of existing and expansion resources along with incremental acquisition of demand-side management (DSM) resources.

Consumer Rate Impacts

The company estimates no incremental rate impact associated with reducing carbon emissions to meet Goal #1 or Goal #2. This change compared to the 2016 report is due to the business-as-usual reduction in reliance on the company's coal units, reducing the amount of required emission reductions to zero. Table 6 below depicts the shift from coal to natural gas that has already happened since 2016.[12]

Table 6: PacifiCorp Estimated Capacity Factors, 2016 vs 2018 Report[13]

	2016	2018	Percent Change
Coal	68.6%	52.0%	**-32.1%**
Natural Gas	48.4%	89.8%	**85.5%**

[12] A plant's capacity factor is the ratio between the plant's total (nameplate) capacity and the energy it actually produces each year.

[13] As there have been no major coal or natural gas additions between 2016 and 2018 reports, the change in fleet capacity factor reflects change in total output from existing plants.

Idaho Power Company

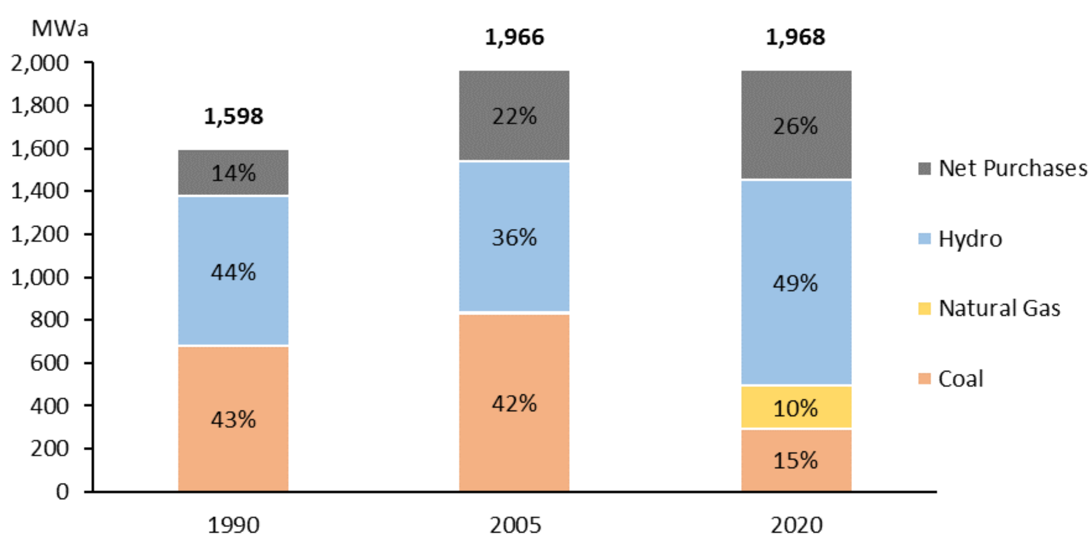
Utility Background

Idaho Power Company (Idaho Power or IPC) is an investor-owned electric utility with a small service territory in Oregon with a predominantly hydroelectric generating base. Idaho Power owns and operates 17 hydroelectric plants on the Snake River and its tributaries. Idaho Power also delivers power to its customers through one diesel-powered generator and shared ownership in three coal-fired generating plants. Idaho Power also owns three natural gas-fired plants, whose higher utilization is seen in both Table and Figure 7 below.

Table 7: Idaho Power Energy Portfolio IRP Comparison (System-Wide)

2020 Total System – Load / Resource Balance (MWh)			
	(A)	(B)	(B - A)
Generation Type	**2015 IRP Energy Sources**	**2017 IRP Energy Sources**	**Difference**
Hydro	8,631,843	8,457,924	(173,920)
Coal	4,916,312	2,590,361	(2,325,951)
Natural Gas	1,116,049	1,736,786	620,737
Resources Total	**14,664,205**	**12,785,070**	**(1,879,135)**
PURPA	3,428,266	2,952,746	(475,520)
PPA/ Other	527,226	550,997	23,771
Market Purchases	352,632	997,094	644,462
Surplus Sales	(2,612,810)	(877,159)	1,735,651
Load	**16,359,518**	**16,408,747**	**49,229**

Figure 7: Idaho Power Energy Portfolio Comparison (System-Wide)



Idaho Power serves over 550,000 customers in Idaho and Oregon with just five percent of its operating revenues from Oregon.

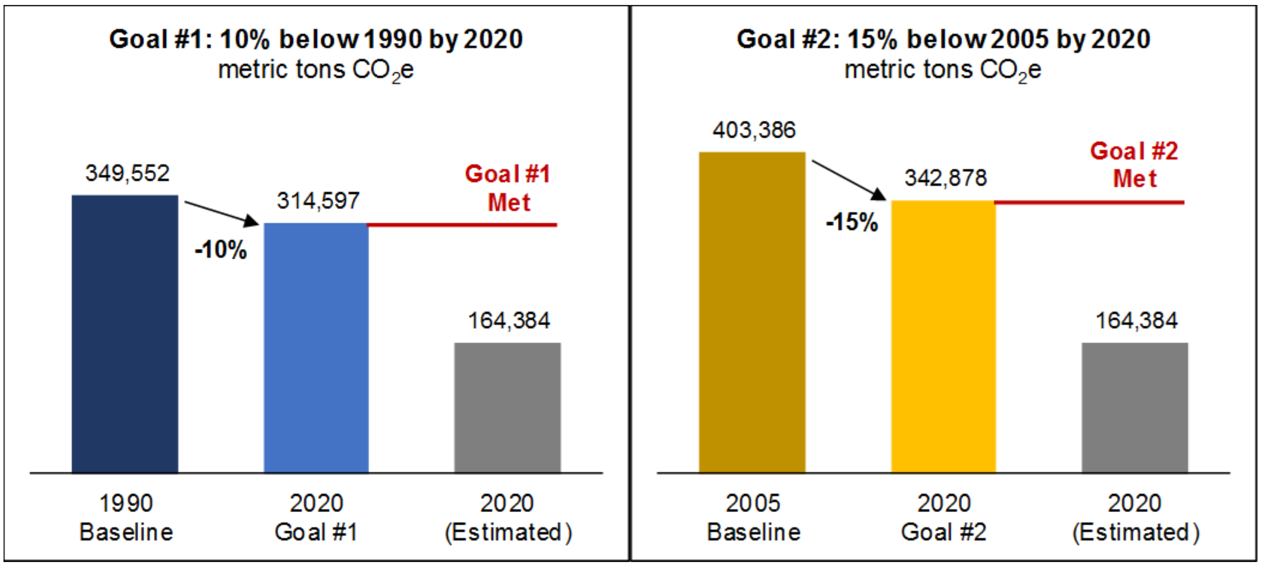
Emissions Reduction Report Information

Both Table and Figure 8 shows that Idaho Power is able to meet both of Oregon's 2020 greenhouse gas emission reduction goals on a business as usual basis.

Table 8: Idaho Power Emissions Comparison Table

Oregon Allocated Emissions (metric tons CO_2)		IPC
Goal #1	1990 Baseline	349,552
	10% reduction	314,597
Goal #2	2005 Baseline	403,386
	15% reduction	342,878
Business as Usual Emissions	2020 Estimate	**164,384**

Figure 8: Idaho Power Emissions Comparison



Using its 2017 Integrated Resource Planning projections, Idaho Power is able to demonstrate compliance with the Legislation's goals. This is due in large part to reducing generation from coal-fired resources compared to earlier projections for 2020 resources. Idaho Power Company's report finds that, due to low natural gas prices and expanded renewable capacity, the company will increase reliance on wholesale market purchases, which have become more economic in recent years compared to coal dispatch, and are comparatively less carbon intensive resources.

Consumer Rate Impacts

The company estimates no incremental rate impact associated with reducing carbon emissions to meet the goals.

Natural Gas Utilities

Northwest Natural

Utility Background

NW Natural Gas Company (NW Natural or NWN) is headquartered in Portland, Oregon. Primarily a natural gas distributor, the company services residential, commercial, and industrial customers in Western Oregon and Southwest Washington. System-wide, the company has more than 740,000 customers and revenues of nearly one billion in U.S. dollars annually. In Oregon, it annually distributes more than 610 million therms to more than 640,000 customers.

NW Natural is Oregon's largest natural gas utility. It serves customers along the Oregon Coast, in the Willamette Valley, the Columbia River Gorge, and the Portland metropolitan area. The company operates an underground natural gas storage facility near Mist, Oregon, in the Northern Oregon Coast Range utilizing depleted gas wells.

Emissions Reduction Report Information

As a local distribution company (LDC), NW Natural supplies natural gas to a number of end uses (primarily space- and water-heating), but does not account for emissions from the end use combustion of that gas as their own, as those emissions would accrue to the individuals or firms that made the choice to burn the gas. Instead, the company has identified four sources of GHG emissions for which it is wholly responsible, including

1. operations and facilities,
2. natural gas and electric power usage for operations, including compressors,
3. operation of fleet vehicles to service customers, and
4. very small natural gas leaks (commonly referred to as fugitive emissions).

NW Natural does not have historical data necessary for determining its 1990 or 2005 GHG emissions. For this report, NW Natural uses the average emissions for 2008 and 2009 as the proxy for both 1990 and 2005 baselines. The company believes this is a reasonable assumption because, despite serving more customers (319,962 customers in 1990, 617,162 in 2005), the company claims it is more efficient, has fewer small leaks due to the system integrity program, and has fewer employees operating vehicles now compared to 1990. If the increase in emissions from a larger customer base outweighs decrease in emission from system efficiencies, emissions in 1990 and 2005 (and the associated goals) could be lower than are reported here, leading to an overestimation of the emissions limits for 2020 and underestimation of the estimated rate impacts of meeting the GHG mitigation goals.

Further, the company did not conduct an analysis to forecast its four sources of GHG emissions. Instead, it relied on using 2017 historic emissions data as a proxy, despite forecasted growth in demand. The company justifies this assumption by assuming emissions related to its fleet and office facilities will remain steady or decline through 2020, and does not foresee significant reductions to gas storage and compression, but rather assumes that efficiency gains could offset the impact of increased operations. Similar to the above, the PUC cannot evaluate the claim that system efficiencies will offset any growth. If emissions increase between 2017 and 2020, the alleged rate impacts presented here will be an underestimation.

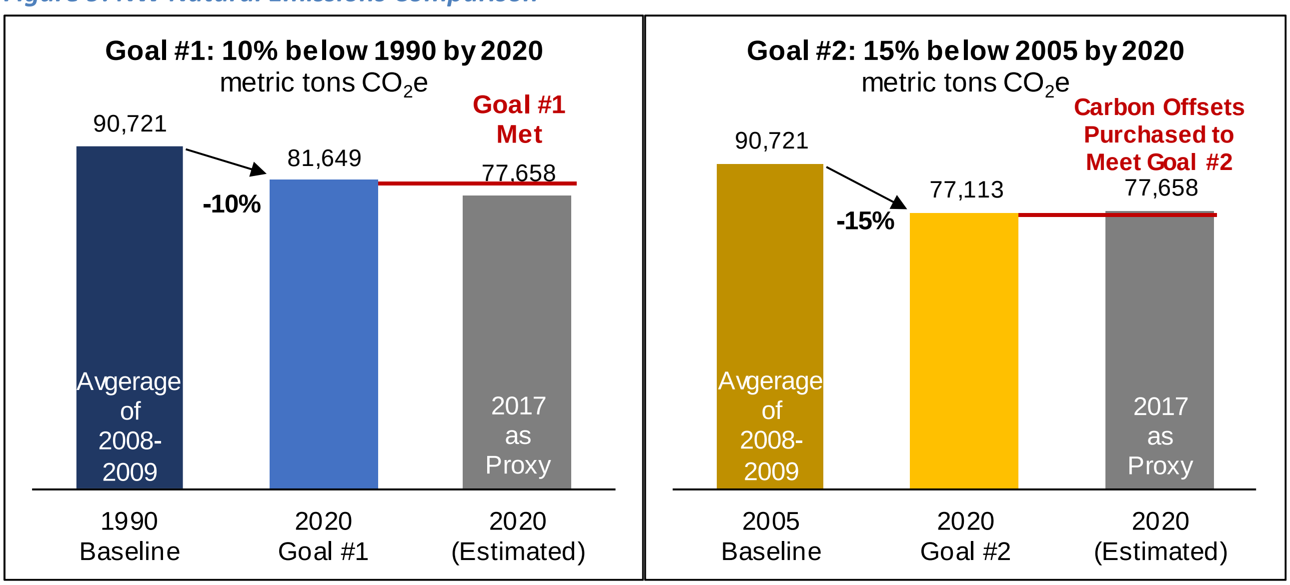
There are two key points about NW Natural's emissions that highlight significant uncertainty in the estimates. First, the majority of the emissions come from fugitive emissions associated with NW Natural's distribution system, which are not measured values. NW Natural takes a prescribed value from the U.S. Environmental Protection Agency (EPA). These may be the best available estimates, but may also miss some particularities in NW Natural's system. Second, the next largest source of emissions (gas storage and distribution) is highly variable and dependent on how NW Natural decides to move gas across its system. Any forecasts should have a wide variance. Combined, these two points highlight the uncertainty of any emission estimates, as well as the associated cost projections based on them.

Since emissions from both the 1990 and 2005 are assumed to be the same, the two goals differ only by 5 percent. As seen in both Table and Figure 9, NW Natural estimates that it is meeting Goal #1, but not Goal #2.

Table 9: NW Natural Emissions Comparison Table

Total System Emissions (metric tons CO_2e)		**NWN**
Goal #1	1990 Baseline	90,721
	10% reduction	81,649
Goal #2	2005 Baseline	90,721
	15% reduction	77,113
Business as Usual Emissions	2020 Estimate	**77,658**

Figure 9: NW Natural Emissions Comparison



Consumer Rate Impacts

NW Natural believes that actual emission reduction activities and their associated costs cannot be known or even assumed. Accordingly, the company believes it can meet this small shortfall by purchasing offsets. NW Natural assumes the cost of offsets to be $12.55 per metric ton, and would therefore need to spend $6,840 to achieve Goal #2. As shown in Table 8, spread across their more than 740,000 customers, this would add less than a penny to each customer's yearly rates.

Table 10: Cost Impact to NW Natural Customers to Meet 2020 Goals

	Goal #1 (1990 Baseline)	Goal #2 (2005 Baseline)
Estimated Total Cost of Carbon Abatement Using Offsets	$0	$6,840
Estimated Cost per Customer account per year	$0.000	$0.009

Cascade Natural Gas

Utility Background

Today, Cascade serves more than 70,000 customers across 28 communities in Oregon. Along with service territory in Washington, CNG serves customers in and surrounding Bend, Pendleton, Baker City and Ontario.

Emissions Reduction Report Information

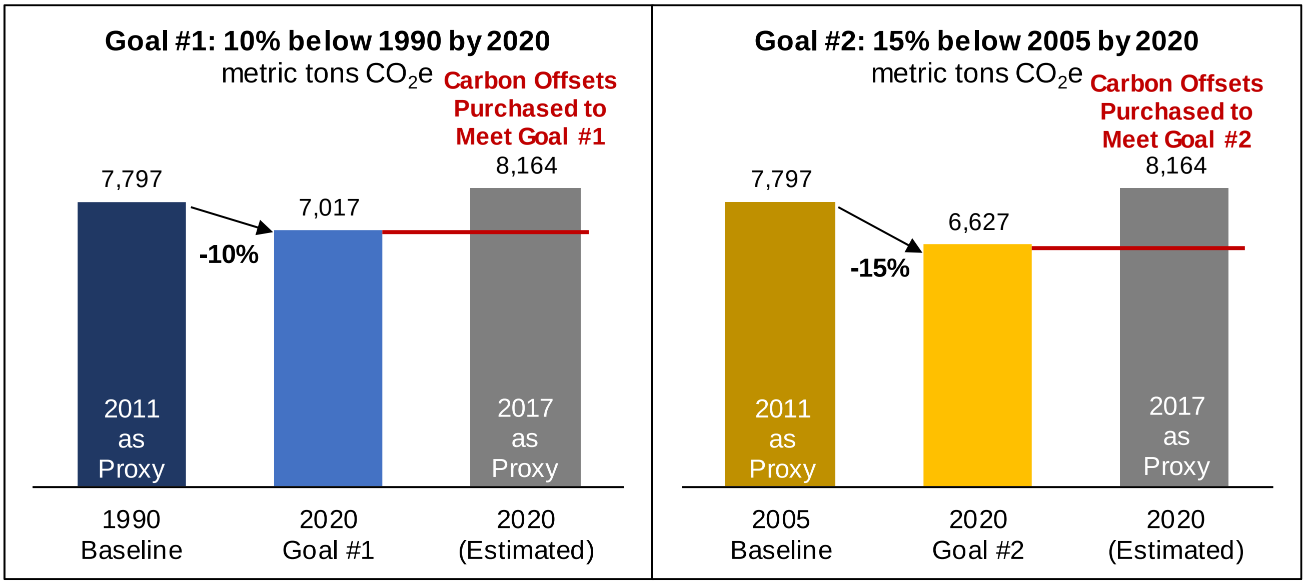
Cascade Natural Gas (CNG) has identified three sources of GHG emissions from its Oregon operations including heating office facilities, the use of company vehicles, and the fugitive emissions from its Oregon distribution system. The company does not have historical data available for determining its 1990 or 2005 greenhouse gas emissions, so the company chose to report 2011 data to set a baseline. CNG is transparent in this assumption and states they are not able to claim this to be an accurate representation, though it is currently the best available benchmark for all three emissions sources. In addition to this, the company does not forecast emissions into the future, but uses 2017 emissions as a proxy for the 2020 target year, claiming it to be a reasonable substitution. CNG's reasoning for this substitution is noted as the difficulty of forecasting emissions, and the expectation that any increases in emissions from the fleet may be offset by improved fuel efficiency in vehicles or the use of alternative fuels in vehicles, however, no quantitative evidence supporting these claims has been provided.

Using these proxies, the company highlights how business as usual action will lead to higher emissions than the legislature's GHG goals in 2020, as displayed in Table 11 and Figure 10.

Table 11: CNG Emissions Comparison Table

Total System Emissions (metric tons CO_2e)		CNG
Goal #1	1990 Baseline	7,797
	10% reduction	7,017
Goal #2	2005 Baseline	7,797
	15% reduction	6,627
Business as Usual Emissions	2020 Estimate	**8,164**

Figure 10: CNG Emissions Comparison



Consumer Rate Impacts

The company proposes purchasing emission offsets as the sole way to mitigate their emissions in order to meet the 2020 targets. Assuming an offset price of $15.54 per metric ton, CNG estimates the total cost of meeting the GHG reduction goals to be $17,824.38 and $23,884.98 for Goals #1 and #2, respectively. Spread over its 70,000 customers in Oregon, meeting these emission targets would cost an average of $0.25 and $0.34 per customer per year. The company notes that offset prices vary based on the type of project from which they are developed, and the future cost of offsets is speculative since costs may be impacted by higher demand resulting from either local or federal carbon legislation. The offset price assumed by CNG represents the May 2018 Joint Auction Settlement price of $14.65 as reported by the California Air Resources Board, escalated by 3 percent each year to estimate a 2020 price.

Table 12: Cost Impact to CNG Customers to Meet 2020 Goals

	Goal #1 (1990 Baseline)	Goal #2 (2005 Baseline)
Estimated Total Cost of Carbon Abatement Using Offsets	$17,824.38	$23,884.98
Estimated Total Cost per Customer of Carbon Abatement Using Offsets	$0.25	$0.34

The results for CNG presented in this report differ greatly compared to the company's 2016 report, which included estimates of fugitive emissions for the first time. In reviewing the calculations that were used to determine the proxy emissions for 1990 and 2005, and the 2015 fugitive emissions, CNG learned of an error in the calculation used in the 2016 report. Rather than using the number of distribution services by type, the company was using the miles of services by type. For this report, the company has made the corrections to the 2011 calculations and updated the 1990 and 2005 fugitive emissions estimates accordingly.

Avista

Utility Background

Avista Utilities generates and transmits electricity and also distributes natural gas for residential, commercial, and industrial customers. Approximately 1,550 employees provide electricity, natural gas, and other energy services to 359,000 electric and 320,000 natural gas customers in three western states. Its service territory covers 30,000 square miles in eastern Washington, northern Idaho, and parts of southern and eastern Oregon, serving a population of 1.6 million people. The company was founded in 1889 as Washington Water Power Company, until 1998, when the board of directors approved a name change to Avista Utilities. In Oregon, Avista serves natural gas customers in La Grande, Roseburg, Medford, and Klamath Falls.

Emissions Reduction Report Information

Avista has identified three sources of GHG emissions including consumption at its office facilities, its transportation fleet, and fugitive emissions from its distribution system. Avista does not have historical energy usage information or fuel consumption from its fleet vehicles available in order to calculate its 1990 and 2005 GHG emissions. Therefore, for the purposes of this report, the company uses the average emissions from 2009 through 2011, 9,557 metric tons, as a proxy for both its 1990 and 2005 emissions levels. While it provides no quantitative evidence supporting this claim, the company believes this to be a reasonable and conservative assumption because

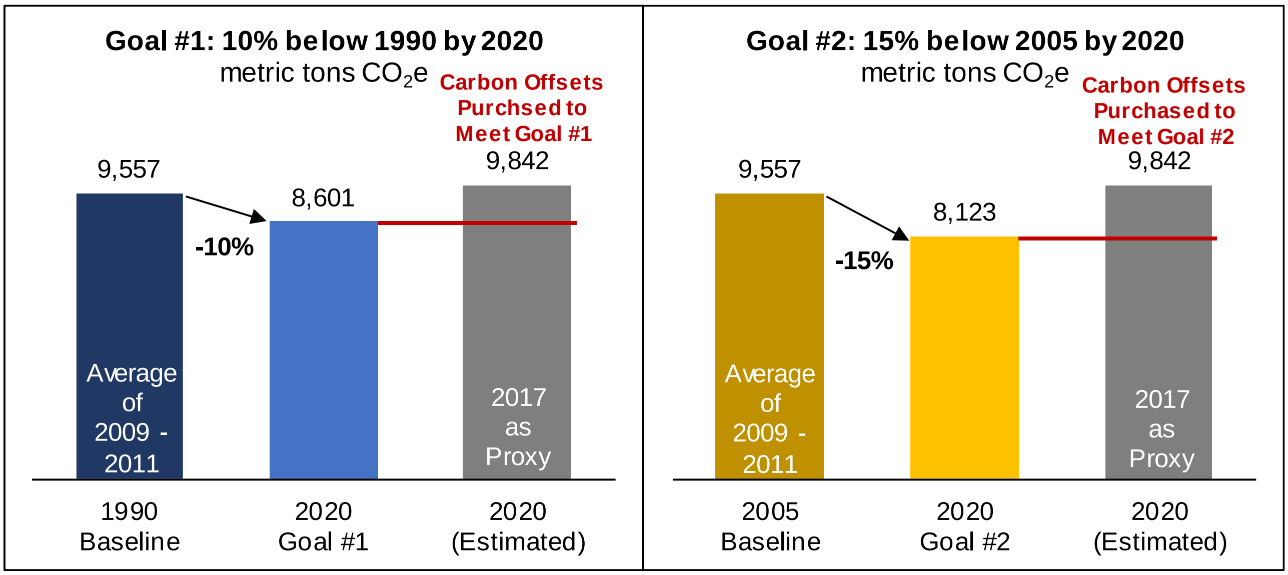
- Avista has the same number of overall office and operational facilities; however several of the facilities have had energy efficiency upgrades since 1990 and 2005. The company has also reduced staffing, particularly as it relates to Contact/Call Center operations and meter readers due to a reduction in meter reading with the deployment of Automated Meter Reading (AMR) in 2004.
- The company is operating fewer vehicles due to, among other things, a reduction in meter reading with the deployment of AMR as mentioned above.

By using an average emissions proxy of 2009 to 2011, that also includes other average proxy data, the baseline emissions associated with buildings, vehicles, and fugitive emissions from the distribution system are likely lower than it was both in 1990 and 2005. The baseline proxy is an average of three years of data, including 2009 and 2010 which incorporate substitution data for the LDC's fugitive emissions as the average of the historic reported data for the years which Avista reported to the EPA Greenhouse Gas Mandatory Reporting Regulation at 40 CFR 98, Subpart W Petroleum and Natural Gas Systems. Reporting was limited to years 2011 through 2014 as the Company discontinued reporting fugitive emissions in Oregon for any other year in which total emissions had proven less than the 15,000 metric tons EPA reporting requirement threshold. The 2011 to 2014 fugitive emission average of 9,125 metric tons is substituted in all years for which Avista did not report to EPA, including for historic 2017 data, which is used below as proxy for 2020 in Table 13 and Figure 11.

Table 13: Avista Emissions Comparison Table

Total System Emissions (metric tons CO_2e)		Avista
Goal #1	1990 Baseline	9,557
	10% reduction	8,601
Goal #2	2005 Baseline	9,557
	15% reduction	8,123
Business as Usual Emissions	2020 Estimate	**9,842**

Figure 11: Avista Emissions Comparison



The company estimates that overall emissions between 2017 and 2020 will remain relatively flat, as any emissions reductions could be offset by increased emissions caused by adding customers to their service. As seen in Figure 11, there are currently shortfalls between estimated emissions in 2020 (using 2017 as a proxy) and meeting GHG reduction Goals #1 and #2. Avista notes that that their emissions in recent years are low to begin with in context of total carbon dioxide emissions across the state of Oregon, though they aim to continue to investigate energy efficiency measures at office facilities, and less carbon-intensive fleet vehicles such as CNG and hybrids.

Consumer Rate Impacts

Though it is not explicitly stated, it is assumed that Avista intends to purchase offsets at a cost of the Social Cost of Carbon, currently forecasted to be $17.86 per ton. Spread across its 99,343 customers, this yields a $0.22 and $0.31 average increase in annual cost per Oregon customer to achieve Goals #1 and #2, respectively. Avista uses the social cost of carbon because it is one of the only estimated industry values available that provides a reasonable basis for carbon pricing in the absence of any regional carbon market indices. It has been used by regional lawmakers in proposed carbon reduction policies as a means to price the cost of offsetting the long term carbon impacts to the climate.

Table 14: Cost Impact to Avista Customers to Meet 2020 Goals

	Goal #1 (1990 Baseline)	**Goal #2 (2005 Baseline)**
Estimated Total Cost of Carbon Abatement Using Offsets	$22,159	$30,693
Estimated Total Cost per Customer of Carbon Abatement Using Offsets	$0.22	$0.31

Appendix

Appendix 1

Executive Summary of 2016 Report

The 2009 Legislature enacted Senate Bill 101 (SB 101) to require the Oregon Public Utility Commission to report before November 1 of each even-numbered year on the estimated rate impacts of Oregon's regulated electric and natural gas utilities achieving two greenhouse gas emission targets. The emission reduction targets are:

SB 101 is an uncodified law; as such, it does not have an Oregon Revised Statutes (ORS) citation.

- Reduce greenhouse gas emissions 10 percent below 1990 levels by 2020.
- Reduce greenhouse gas emissions 15 percent below 2005 levels by 2020.

Electric Company Reductions and Rate Impacts

Greenhouse gases are emitted from the burning of fossil fuels (coal and natural gas) to generate electricity to supply the Oregon customers of Idaho Power Company (Idaho Power), PacifiCorp, and Portland General Electric Company (PGE). Idaho Power, PacifiCorp, and PGE identified additional resource actions they would need to take to achieve the greenhouse gas emissions reduction goals and then estimated the incremental rate impact of those actions.

Idaho Power – Under its current resource plan, Idaho Power is on track to achieve emission levels lower than both of the target levels. Because no additional actions are necessary, Idaho Power estimates zero rate impact with achieving the two emission reduction targets.

PacifiCorp – Under its current resource plan, projected emissions in 2020 would exceed both targets. To comply with the 10 percent reduction in emissions below 1990 levels, PacifiCorp would have to reduce its projected greenhouse gas emissions in 2020 by an estimated 16 percent. PacifiCorp assumes that it would reduce coal-fired generated electricity delivered to Oregon (and increase generation from its natural gas power plants by a like amount) to meet the target. PacifiCorp's estimated electricity rates in 2020 increase by 0.38 percent or an annual average bill impact of $6.68 per residential customer.

To meet the 15 percent reduction below 2005 levels, PacifiCorp would have to reduce its projected greenhouse gas emissions in 2020 by an estimated 1 percent. PacifiCorp again assumes it would stop delivery of generation from its coal-fired power plants to Oregon (and increase it at natural gas-fired power plants) to meet the target. PacifiCorp estimates an increase cost of $1M over the base case, or $0.01 per residential customer.

Portland General Electric – Under PGE's current resource plan, PGE is on track to comply with the 15 percent below 2005 emission level target. Accordingly, there is no rate impact to meet this target.

To comply with the 10 percent reduction in emissions below 1990 levels, PGE would have to reduce emission in 2020 by an estimated 34 percent. PGE assumes it would shut down Boardman (as planned), discontinue taking service from the Colstrip coal units, and replace all discontinued generation with carbon-free resources such as wind and solar generation. PGE's electricity rates in 2020 would be about 34.2 percent higher than as projected in their 2014 IRP.

Natural Gas Company Reductions and Rate Impacts

Avista Utilities (Avista), Cascade Natural Gas Corporation (Cascade), and Northwest Natural Gas Company (NW Natural) serve Oregon's natural gas customers. These companies directly emit a small amount of greenhouse gases through distribution system and gas equipment leaks and direct burning for facility use and natural gas fleet vehicles (their emissions do not include emissions from the direct burning of natural gas for Oregon homes and businesses).

Northwest Natural, Cascade, and Avista each identified basic actions they could take to achieve the emission reduction targets. The rate impacts of the actions are minimal.

Appendix 2

Executive Summary of 2014 Report

The 2009 Legislature enacted SB 101 to require the Oregon Public Utility Commission to report before November 1 of each even-numbered year on the estimated rate impacts of Oregon's regulated electric and natural gas utilities achieving two greenhouse gas emission targets. The emission reduction targets are:

- Reduce greenhouse gas emissions 10 percent below 1990 levels by 2020.
- Reduce greenhouse gas emissions 15 percent below 2005 levels by 2020.

Electric Company Reductions and Rate Impacts

Greenhouse gases are emitted from the burning of fossil fuels (coal and natural gas) to generate electricity to supply the Oregon customers of Idaho Power Company (Idaho Power), PacifiCorp, and Portland General Electric Company (PGE). Idaho Power, PacifiCorp, and PGE identified additional resource actions they would need to take to achieve the greenhouse gas emissions reduction goals and then estimated the incremental rate impact of those actions.

Idaho Power – Under its current resource plan, Idaho Power is on track to achieve emission levels lower than both of the target levels. Because no additional actions are necessary, Idaho Power estimates zero rate impact with achieving the two emission reduction targets.

PacifiCorp – Under its current resource plan, projected emissions in 2020 would exceed both targets. To comply with the 10 percent reduction in emissions below 1990 levels, PacifiCorp would have to reduce its projected greenhouse gas emissions in 2020 by an estimated 16 percent. PacifiCorp assumes that it would reduce generation from its coal-fired power plants (and increase generation from its natural gas power plants by a like amount) to meet the target. PacifiCorp's estimated electricity rates in 2020 would be about 5.7 percent higher than otherwise projected.

To meet the 15 percent reduction below 2005 levels, PacifiCorp would have to reduce its projected greenhouse gas emissions in 2020 by an estimated 2.7 percent. PacifiCorp again assumes it would cut generation at its coal-fired power plants (and increase it at natural gas-fired power plants) to meet the target. Electricity rates in 2020 would be about 0.5 percent higher than otherwise projected.

Portland General Electric – Under PGE's current resource plan, PGE is on track to comply with the 15 percent below 2005 emission level target. Accordingly, there is no rate impact to meet this target.

To comply with the 10 percent reduction in emissions below 1990 levels, PGE would have to reduce emission in 2020 by an estimated 42 percent. PGE assumes it would shut down Boardman (as planned), discontinue taking service from the Colstrip coal units, and replace all discontinued generation with carbon-free resources such as wind and solar generation. PGE's electricity rates in 2020 would be about 39 percent higher than projected otherwise.

Natural Gas Company Reductions and Rate Impacts

Avista Utilities (Avista), Cascade Natural Gas Corporation (Cascade), and Northwest Natural Gas Company (NW Natural) serve Oregon's natural gas customers. These companies directly emit a small amount of greenhouse gases through distribution system and gas equipment leaks and direct burning for facility use and natural gas fleet vehicles (their emissions do not include emissions from the direct burning of natural gas for Oregon homes and businesses).

Northwest Natural, Cascade, and Avista each identified basic actions they could take to achieve the emission reduction targets. The rate impacts of the actions are minimal.

Appendix 3

Executive Summary of 2012 Report

The 2012 *Greenhouse Gas Reduction Goal Rate Impact Report* submitted to the legislature by the Public Utility Commission found the following:

10 percent below 1990 levels by 2020:

- **Idaho Power** would have to **reduce its greenhouse gas emissions in 2020 by two percent** from the level projected in its 2011 Integrated Resource Plan (IRP). Idaho Power assumes that it would meet that emissions goal by curtailing coal-fired generation. Idaho Power's estimated electricity rates in 2020 would be about **0.1 percent higher than current rates**.
- **PacifiCorp** would have to **reduce its greenhouse gas emissions in 2020 by 23 percent** from the level projected in its most recent 2010 IRP. PacifiCorp assumes that it would have to reduce generation from its coal-fired plants and add significant amounts of renewable resources, natural gas-fired resources, energy conservation, and demand response resources. PacifiCorp's estimated electricity rates in 2020 would be eight **percent higher than current rates**.
- **PGE** would have to **reduce its greenhouse gas emissions in 2020 by 54 percent** from the level projected in its current IRP. To reduce emissions, in addition to the planned shutdown of its Boardman coal-fired plant, PGE assumes that it would have to discontinue taking service from the Colstrip coal-fired power plant and replace the associated generation with renewable resources, among other actions. Following this course of action, PGE's estimated electricity rates in 2020 would be **34 percent higher than current rates.**

15 percent below 2005 levels by 2020:

- **Idaho Power** would have to reduce its greenhouse gas emissions in 2020 by two percent from the level projected in its 2011 IRP, which is similar to meeting *the 10 percent below 1990 goal*. Idaho Power assumes that it would meet that emissions goal by curtailing coal-fired generation. Idaho Power's estimated electricity rates in 2020 would be about **0.1 percent higher than current rates**.
- **PacifiCorp** would have to **reduce its greenhouse gas emissions in 2020 by 11 percent** from its projected 2010 IRP level. PacifiCorp assumes that it would reduce generation from its coal-fired plants and add natural gas fired resources, energy conservation, and some renewable resources. PacifiCorp's electricity rates in 2020 would be four **percent higher than current rates.**
- **PGE** would have to **reduce its greenhouse gas emissions in 2020 by 20 percent** from the projected 2010 IRP level. PGE assumes it would achieve this goal through the planned shutdown of its Boardman coal-fired plant, discontinue taking service from the Colstrip coal-fired power plant, and replacing the associated generation with a mix of natural gas and renewable

resources, among other actions. PGE's electricity rates would be an estimated eight **percent to 14 percent higher than current rates.**

Natural Gas Company Reductions and Rate Impacts

The greenhouse gas emissions attributable to Oregon's natural gas companies – Avista, Cascade, and NW Natural – largely stem from distribution system and gas equipment methane leaks. Their greenhouse gas emissions also include company facility energy usage and operation of company fleet vehicles. These emissions do not include the emissions from burning natural gas directly in homes and businesses, and are small in comparison to the emissions from direct burning of natural gas.

For this report, Avista, Cascade, and NW Natural identified actions that each could take to achieve the greenhouse gas emissions reduction goals. The three natural gas companies estimate that each would have to reduce their 2020 emissions by 10 percent to reach the *10 percent less than 1990 goal* and 15 percent to reach the *15 percent less than 2005 goal*. To meet the greenhouse gas emissions reduction goals the estimated rate increase is significantly less than one percent for each of the three natural gas companies.