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October 5, 2021

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
Detailed Depreciation Study of Electric Utility Properties.
Docket No. UM 2152

Dear Filing Center:

Please find enclosed the Cross-Examination Exhibits (AWEC/200-213) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that Exhibit AWEC/209 contains Protected Information that is being handled in accordance with Order No. 21-017. The confidential version of Exhibit AWEC/209 has been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served **Confidential Exhibit AWEC/209** upon the parties shown below via electronic mail.

Dated at Portland, Oregon, this 5th day of October, 2021.

Sincerely,

<u>/s/ Jesse O. Gorsuch</u>
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2152

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Detailed Depreciation Study of Electric Utility Properties.	CROSS-EXAMINATION EXHIBITS OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

Pursuant to the Administrative Law Judge's Ruling issued on August 16, 2021, the Alliance of Western Energy Consumers submits the following cross-examination exhibits for the hearing scheduled for October 11, 2021, in the above-referenced Docket.

Cross-Examination Exhibit	Description
AWEC/200	FERC Order Accepting Depreciation Rates, Docket Nos. ER11-2584-000 and ER11-2579-000 (Feb. 28, 2011)
AWEC/201	FERC Order on Retail Adjustments to Depreciation Reserves, Docket No. ER11-3584-000 (July 15, 2011)
AWEC/202	Excerpt of Florida Public Service Commission Order No. PSC-10-0153-FOF-EI, Docket Nos. 080677-EI and 090130-EI (Mar. 17, 2010)
AWEC/203	Excerpt of Depreciation Systems, Frank K. Wolf and W. Chester Fitch (1994)
AWEC/204	Excerpt of Public Utility Depreciation Practices, NARUC (Aug.1996)
AWEC/205	Excerpt of PacifiCorp's 2017 Depreciation Study, Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2017

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Cross-Examination Exhibit	Description
AWEC/206	Excerpt of Puget Sound Energy's 2016 Depreciation Study, Calculated Annual Depreciation Accruals Related to Electric, Gas, and Common Plant as of September 30, 2016
AWEC/207	Direct Testimony of PacifiCorp Witness John J. Spanos in Docket No. UM 1968 (Sept. 2018)
AWEC/208	Excerpt of Arizona Corporation Commission Decision No. 75975, Docket Nos. E-01933A-15-0239 and E-01933A-15-0322
Confidential AWEC/209	Confidential PGE Response to AWEC Data Request 024 and Confidential Attachment "PGE data questions.pdf" to PGE Response to AWEC DR 005
AWEC/210	PGE Response to AWEC Data Request 023
AWEC/211	PGE Response to AWEC Data Request 046 and Attachment A thereto
AWEC/212	PGE Response to AWEC Data Request 064
AWEC/213	Idaho Public Utilities Commission Order No. 3296, Case No. PAC-E-13-02

Dated this 5th day of October, 2021.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

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134 FERC ¶ 61,145
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Florida Power Corporation — Docket No. ER11-2584-000

Carolina Power & Light Company — Docket No. ER11-2579-000

ORDER ACCEPTING DEPRECIATION RATES

(Issued February 28, 2011)

1. On December 30, 2010, pursuant to section 205 of the Federal Power Act (FPA),[1] Florida Power Corporation (Florida Power) and Carolina Power & Light Company (Carolina Power) separately filed revised depreciation rates for use in the formula rates contained in each of their Open Access Transmission Tariffs (OATT). In this order, we accept the revised depreciation rates to be effective January 1, 2010, as requested, for the reasons discussed herein.

I. **Background**

2. As the result of a merger consummated in 2000, Florida Power and Carolina Power operate pursuant to two individual but identically maintained tariffs that contain separate depreciation rates for each individual company and rates for their transmission services.[2]

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[1] 16 U.S.C. § 824d (2006).

[2] *See CP&L Holdings, Inc.*, 92 FERC ¶ 61,023, at 61,051, 61,059-61,061 (2000). The OATTs are designated as Carolina Power & Light Company, Fourth Revised Volume No. 3 and Florida Power Corporation, Third Revised Volume No. 6.

On July 14, 2010, Florida Power and Carolina Power each filed their OATTs in separate baseline eTariff filings.[3]

3. In their December 30 filings, Florida Power and Carolina Power propose to revise only Florida Power's depreciation rates, which are included in Schedule 10 of the respective OATTs, to reflect the depreciation rates approved by the Florida Public Service Commission (Florida Commission).[4] The Florida Commission requires jurisdictional utilities to file remaining life depreciation rates every four years.[5] The depreciation rates approved by the Florida Commission are based upon a depreciation study conducted by Florida Power in early 2009 that used projected 2008 and projected 2009 plant balances (2009 Depreciation Study),[6] with modifications for plant lives, reserve allocations, net salvage and interim retirement ratios as deemed appropriate by the Florida Commission as a result of a fully litigated rate case proceeding.[7] Florida Power states that the approved rates were calculated using the straight line remaining life depreciation method, with the average service life procedure, and were prepared in accordance with generally accepted practices in the field of depreciation.

4. Florida Power explains that, in accordance with the 2009 Depreciation Study, the depreciation rates for all of its transmission plant accounts, as well as the depreciation rate for one general plant account, Account 390, Structures and Improvements, have been revised. It states that the depreciation rates for transmission and general plant directly impact the formula rate because the formula rate recovers depreciation expense and a return on the net book value associated with these types of plant. The formula rate also uses a net plant allocator to allocate some very limited costs in the formula rate and the net plant allocator is indirectly and minimally impacted by changes in depreciation rates for production and distribution plant. Accordingly, Florida Power also submitted the

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[3] *See Carolina Power & Light Co.*, ER10-1774-000, Sept. 2, 2010 (delegated letter order); *Florida Power Corp.*, Docket Nos. ER10-1775-000 & ER10-1775-001, Oct. 8, 2010 (delegated letter orders).

[4] Florida Power December 30, 2010 Filing at 3.

[5] *Id*. at 3 (citing Fla. Admin. Code Ann. R. 25-6.0436(8)(a) (2011) ("Each company shall file a study for each category of depreciable property for Commission review at least once every four years from the submission date of the previous study unless otherwise required by the Commission.")).

[6] Florida Power December 30, 2010 Filing at 3.

[7] *Id.*

Florida Commission-approved changes to depreciation rates for production and distribution plant for Commission approval.

5. Florida Power states that, consistent with the Florida Commission order, Florida Power implemented the revised retail depreciation rates effective as of January 1, 2010, and additionally adopted them for wholesale accounting purposes as of the same date. Florida Power requests Commission approval to implement the revised depreciation rates effective as of January 1, 2010 for the 2011 Annual Update of the OATT formula rate on June 1, 2011. Florida Power also notes that the revised depreciation rates would be reflected in its 2010 FERC Form No. 1 annual report, which is used as the basis for Florida Power's June 1, 2011 Annual Update and true-up of its OATT formula rate for 2010 service .[8] Florida Power states that Exhibit Nos. PEF-3 and PEF- 4 show that Florida Power's proposed depreciation rates result in a decrease of $839,704 based on calendar year 2009.[9]

6. In its separate filing, Carolina Power explains that the purpose of its filing is to incorporate Florida Power's revisions to its OATT in order to maintain Carolina Power's version of the OATT.[10] Thus, Carolina Power's proposed revisions to its version of the OATT reflect Florida Power's proposed depreciation rates.[11]

7. Florida Power and Carolina Power each request that the Commission allow their filings to become effective on January 1, 2010.[12] Florida Power requests waiver of the prior notice requirement, and argues that good cause exists for this waiver. It states that the Commission ordinarily finds good cause to grant waiver of the prior notice requirement if the effective date of the rate change is prescribed by contract. It explains

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[8] *Id.* at 3-4 & n.9. Florida Power also states that the depreciation rates for the other general plant accounts have not been changed, although some minor changes to the depreciation rates for the other general plant accounts are shown in Exhibit PEF-2. Florida Power states that these minor changes reflect the conversion from the existing blended (wholesale and retail depreciation) rates to the proposed retail rates.

[9] *Id.* at 4 (citing Ex. PEF-3; Ex. PEF-4).

[10] Carolina Power December 30, 2010 Filing at 3.

[11] *Id.* at 3.

[12] Florida Power December 30, 2010 Filing at 5; Carolina Power December 30, 2010 Filing at 3; *see also* 16 U.S.C. § 824d(d) (2006); 18 C.F.R. §§ 35.3(a), 35.11 (2010).

that the OATT formula rate requires Florida Power to use depreciation rates reflected in its FERC Form No. 1 annual report. Florida Power explains that when it completes on June 1, 2011 its Annual Update and true-up of its OATT formula rate for 2010 service, the formula rate true-up will be completed using 2010 data from Florida Power's FERC Form No. 1 (filed by April 1, 2011). Florida Power states that a January 1, 2010 effective date for the revised depreciation rates would enable it to reflect the revised depreciation rates in its June 1, 2011 Annual Update and true-up of its OATT formula rate for 2010 service. Florida Power also states that the Commission has granted waiver of the prior notice requirement in several similar circumstances which implemented revised transmission depreciation rates in OATT formula rates.[13]

II. Notice of Filing and Responsive Pleadings

8. Notices of Florida Power's and Carolina Power's filings were published in the *Federal Register*, 76 Fed. Reg. 1418 (2011); 76 Fed. Reg. 1416 (2011), with interventions or protests due on or before January 20, 2011. No interventions or protests were filed in response to Carolina Power's filing in Docket No. ER11-2579-000. Timely motions to intervene and protests were filed by the Florida Municipal Power Agency (Florida Municipal) and Seminole Electric Power Cooperative, Inc. (Seminole) (collectively, Protestors) in response to Florida Power's filing in Docket No. ER11-2584-000. On February 4, 2011, Florida Power filed an answer to the protests. On February 9, 2011, Protestors jointly filed an answer to Florida Power's answer (Protestors' Answer). On February 16, 2011, Florida Power filed an additional answer to Protestors' Answer (February 16 Answer). On February 17, 2011, Protestors filed a joint answer to Florida Power's February 16 Answer (February 17 Answer).

9. Protestors assert that Florida Power does not disclose or commit to make other depreciation adjustments accepted by the Florida Commission. Protestors explain that one result of setting new depreciation rates is that the depreciation reserves accumulated to date are viewed by the Florida Commission as either too high (if lower depreciation rates are set) or too low (if higher depreciation rates are set). This is because there is a theoretical reserve balance that is "'the calculated balance that would be in the reserve if the life and salvage estimates now considered appropriate had always been applied.'"[14]

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[13] *Id.* (citing *Duke Energy Carolinas, LLC*, 130 FERC ¶ 61,079 (2010); *South Carolina Electric & Gas Co.,* 132 FERC ¶ 61,043 (2010); *Central Hudson Gas & Electric Corp.*, 60 FERC ¶ 61,106, at 61,338 (1992)).

[14] Seminole January 20, 2011 Protest at 4-5 (quoting *In re: Petition for Increase in Rates by Progress Energy Florida, Inc.*, Docket No. 090079-EI, at 45-46 (Fla. Pub. Serv. Comm'n Mar. 5, 2010)).

Seminole argues that where there is a theoretical reserve surplus, as there is with Florida Power, the Florida Commission requires the theoretical reserve surplus to be amortized over a period of years (usually four) to reduce depreciation expense. According to Seminole, this has the dual effect of reducing in the near term recorded depreciation reserve and depreciation expense.[15] Although agreeing with Florida Power that Florida Power must reduce depreciation expense to reflect the amortization of the theoretical reserve imbalances, Seminole argues that Florida Power must obtain Commission authorization before implementing such amortization.[16] Seminole argues that any changes that are made under the formula rate that affect the determination of the ultimate depreciation expense and depreciation reserve are subject to approval by the Commission under section 205 of the FPA.[17]

10. Florida Municipal similarly argues that FPA section 205 requires Florida Power to submit its anticipated depreciation adjustments in this proceeding because it will need to make depreciation-related adjustments to eliminate the theoretical depreciation reserve to comply with the Florida Commission's directive.[18] In addition to the revised depreciation rates proposed here, Florida Municipal asserts that Florida Power plans to adjust its depreciation expense to reflect amortization of the excess depreciation reserve. According to Florida Municipal, any change to the depreciation expense will affect the price of transmission calculated by the formula rate contained in the OATT.

11. Protestors both argue that Florida Power's current proposal is inconsistent with Order No. 618 because its proposal does not address the amortization of the excess depreciation reserves.[19] In Order No. 618, the Commission stated that utilities would first have to make a filing under FPA section 205 or 206 in order to reflect a change in depreciation rates for ratemaking purposes. Protestors rely on the Commission's statement in Order No. 618 that its intention was merely to authorize "utilities to change their method of depreciation for accounting purposes only; it [did] not authorize any utility to change prices charged for power sales or transmission services . . . to reflect a

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[15] *Id.*

[16] *Id.* at 6.

[17] *Id.* at 6-7.

[18] Florida Municipal January 20, 2011 Protest at 6-7.

[19] *Id.* at 8; Seminole January 20, 2011 Protest at 7 (citing *Depreciation Accounting*, Order No. 618, FERC Stats. & Regs., Regulations Preambles 1996-2000 ¶ 31,104, at 31,695 n.25 (2000)).

change in depreciation."[20] Thus, Protestors argue the Commission should require Florida Power to supplement its filing and require it to demonstrate that it is making the adjustments necessary to eliminate its excess depreciation reserve because "transmission rates will be affected by [those] adjustments to the transmission expense beyond the revised depreciation rates."[21]

12. In its answer, Florida Power contends Protestors' arguments should be dismissed because they are beyond the scope of this proceeding.[22] Florida Power argues that the current proceeding concerns its request to adopt depreciation rate changes at wholesale in its OATT formula rate. Florida Power argues that Protestors' arguments concerning theoretical reserves are "only properly heard in response to a Section 206 complaint brought by the Customers or in a Section 205 filing by the company."[23] However, to eliminate further dispute concerning the theoretical reserves issue, Florida Power states that it:

> [C]ommits to make a Section 205 filing to incorporate the impact of the "theoretical reserves" issue in the OATT Formula Rate for service in 2010 and to request a January 1, 2010 effective date for the filing . . . . [Florida Power] commits to make this Section 205 filing after its 2010 [FERC Form No. 1] data becomes available in April 2011 and before its 2010 Annual Update begins on May 14, 2011.[24]

Florida Power argues that its 2010 FERC Form No. 1 data will not be available until April 2011, and therefore, the data, facts and actual quantitative impact of this issue on the OATT formula rate for service in 2010 will not be available for the Commission's consideration until that time.

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[20] Order No. 618, FERC Stats. & Regs., Regulations Preambles 1996-2000 ¶ 31,104 at 31,695 n.25.

[21] Florida Municipal January 20, 2011 Protest at 8; *see also* Seminole January 20, 2011 Protest at 7-8.

[22] Florida Power February 4, 2011 Answer at 5.

[23] *Id.* at 5-6.

[24] *Id.* at 6.

13. In their answer to Florida Power's answer, Protestors reiterate their position that Florida Power is obligated to obtain Commission authorization for the amortization of the excess reserve imbalances.[25] Protestors characterize Florida Power's commitment to submit a section 205 filing later this year as being "purely discretionary," and they argue that this commitment does not bind Florida Power to make a filing next year to track the impact on 2011 rates.[26] Protestors assert that if Florida Power elects not to submit the section 205 filing, they will be denied the opportunity to review the depreciation-related changes in 2011.[27] Protestors also argue that Florida Power is attempting to bifurcate the depreciation rate and excess reserve amortization issues, which will result in differing practices between the Florida Commission and this Commission. Protestors claim that this separation would produce erroneous formula rate results or inaccurate reporting on Florida Power's FERC Form No. 1.[28] Protestors urge the Commission to require Florida Power to supplement its filing so that "the entirety of the [Florida Commission] depreciation rate order" may be reviewed "to determine the just and reasonable depreciation expense" for Florida Power.[29]

14. In its February 16 Answer, Florida Power restates its position that its proposed revisions to its depreciation rates are the only issue before the Commission and that neither Florida Power nor the Commission are obligated to address the "theoretical reserves" issue at this time.[30] Further, Florida Power observes that Protestors have not challenged the justness or reasonableness of the proposed depreciation rates themselves.[31] With respect to the effect of the revised depreciation rates, Florida Power acknowledges that the revisions will affect 2010 OATT rates, however, it maintains the "theoretical reserves" issue is beyond the scope of this proceeding.[32] Florida Power commits to submit a separate section 205 filing in the future to address these effects. Florida Power

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[25] Protestors February 9, 2011 Answer at 2-3.

[26] *Id*. at 3.

[27] *Id.* at 2.

[28] *Id.* at 4.

[29] *Id*.

[30] Florida Power February 16, 2011 Answer at 3-4.

[31] *Id.*

[32] *Id.* at 4-5. Florida Power does not know the effect of its revisions on the OATT formula rate for service in 2011 or 2012. *Id.*

adds that the Commission has the right to establish wholesale depreciation rates that are the same or diverge from retail depreciation rates.[33] Moreover, Florida Power notes that if the December 30 filings are accepted, then there will be no disparity between the wholesale and retail depreciation rates.[34]

15. In their February 17 Answer, Protestors repeat their position that "to the extent that [Florida Power] is purporting to track the depreciation expense determination of the [Florida Commission] in its 2010 depreciation order, it must do so without parsing the depreciation rate from the amortization of excess reserves, as both are integral to the determination of the depreciation expense."[35] Further, Protestors assert that the issue that must be addressed in the current proceeding is "the principle of tracking the amortization of the excess reserves."[36]

III. Discussion

A. Procedural Matters

16. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2010), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

17. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2010), prohibits an answer to a protest and/or answer unless otherwise ordered by the decisional authority. We will accept the answers filed by Florida Power and the Protestors because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

18. Based on our review of the 2009 Depreciation Study, we find that Florida Power's proposed depreciation rates are just and reasonable. We will therefore accept the proposed depreciation rates as well as the revisions to Carolina Power's version of the OATT to reflect Florida Power's proposed depreciation rates. Further, we will grant

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[33] *Id.* at 3.

[34] *Id.* at 5.

[35] Protestors February 17, 2011 Answer at 1-2.

[36] *Id.* at 2.

waiver of the prior notice requirement to allow these depreciation rates to be effective January 1, 2010, as requested.[37]

19. Under Order No. 618, a utility is allowed to change its depreciation rates for accounting purposes without Commission approval. However, in order to change its rates for jurisdictional power sales or transmission services (whether determined by stated or formula rates) to reflect a change in deprecation, the utility must make a filing pursuant to section 205 of the FPA.[38] In Order No. 618, the Commission required "utilities to use for accounting purposes methods of depreciation that allocate the cost of utility property over its useful service life in a systematic and rational manner."[39] Further, the Commission noted it has traditionally used the straight-line depreciation method to allocate an asset's service value over its remaining life.[40] Florida Power's proposed revisions to its depreciation rates are based on the 2009 Depreciation Study, which uses plant balances, net salvage values and plant retirement data as adjusted by the Florida Commission.[41] The resulting depreciation rates were calculated by allocating gross plant and estimated net salvage, less the accumulated reserve for depreciation, on a straight-line basis over the estimated remaining service life.[42] We find this to be a systematic and rationale method of determining depreciation rates that complies with the requirements of Order No. 618 and is appropriate for wholesale ratemaking purposes. In addition, we note that Protestors do not oppose the proposed revisions to Florida Power's depreciation rates.

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[37] *See Central Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, at 61,338, *order on reh'g*, 61 FERC ¶ 61,089 (1992) ("We will generally grant waiver of the 60-day prior notice requirement in the following instances: . . . (2) filings that reduce rates and charges . . . ."). Florida Power argues, and Protestors do not dispute, that the proposed revisions to the depreciation rates will result in a rate decrease. *See* Florida Power December 30, 2010 Filing at 1. Thus, waiver of the 60-day prior notice requirement is consistent with Commission precedent. *See Central Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106 at 61,338.

[38] Order No. 618, FERC Stats. & Regs., Regulations Preambles 1996-2000 ¶ 31,104 at n.25.

[39] *Id*. at 31,694.

[40] *Id.*

[41] *See* Ex. PEF-5A.

[42] *See* Ex. PEF-5B at 3-9.

20. However, we emphasize that we are only approving in this order the proposed depreciation rates, and not any adjustments to eliminate the theoretical depreciation reserve surplus. Protestors urge the Commission to require Florida Power to supplement its instant depreciation rate change filing so that they may address whether the Florida Commission's approval of amortizations of the theoretical depreciation reserve adjustments are just and reasonable for purposes of Florida Power's jurisdictional rates contained in the OATT.[43] In response, Florida Power commits to make a section 205 filing to address this issue. We agree with Protestors that consistent with Order No. 618, a utility must obtain authorization from this Commission to change prices charged for transmission services to reflect a change in depreciation.[44] We also agree with Protestors that the excess reserve amortizations could impact the reserve balances and depreciation expense, and consequently the formula rate for transmission service. We believe that additions or reductions of depreciation expense to reflect theoretical depreciation reserve amortization clearly falls within depreciation changes that must be filed with the Commission. As the Commission stated in Order No. 618, utilities are not authorized to change prices charged for power sales or transmission service to reflect a change in depreciation.[45] However, we agree with Florida Power that amortization of any excess depreciation reserves can be addressed separately from the determination of whether the proposed depreciation rates themselves are just and reasonable. Thus, we will not require Florida Power to supplement its December 30 filing to address such amortizations.

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[43] Specifically, the Florida Commission approved a settlement that, *inter alia*, grants Florida Power the discretion to credit depreciation expense over three years (2010, 2011, and 2012) with a reserve surplus of at least $647 million based upon a theoretical reserve calculation. *See* Seminole January 20, 2011 Protest, Att. 1; *Id.* Att. 2, at 2-3. In addition, the Florida Commission approved a four-year amortization of a reserve surplus in the annual amount of $5.8 million. *See* Seminole January 20, 2011 Protest, Att. 1; *Id.* Att. 2, at 2-3.

[44] In this regard we note that this Commission has addressed any alleged excess or deficiency in depreciation reserves through adjustment of depreciation rates that eliminate such excess or deficiency over the remaining life of a utility's plant, rather than any shorter period. *See, e.g.*, *Virginia Electric and Power Co.*, 11 FERC ¶ 63,028 (1980), *aff'd in relevant part*, 15 FERC ¶ 61,052 (1981) *Municipal Light Boards of Reading and Wakefield, Mass. v. Boston Edison Co.*, 53 FPC 1545, 1558-59, (1975), *modified*, 54 FPC 440, 442 (1975), *aff''d sub nom. Towns of Norwood v. FPC*, 546 F.2d 1036, 1038 (D.C. Cir. 1976)

[45] Order No. 618, FERC Stats. & Regs., Regulations Preambles 1996-2000 ¶ 31,104 at 31,695 n.25.

The Commission orders:

(A) Florida Power's proposed depreciation rates are hereby accepted for filing to become effective January 1, 2010, as discussed in the body of this order.

(B) Carolina Power's revisions to its version of the OATT are hereby accepted, to be effective January 1, 2010, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

136 FERC ¶ 61,033
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Florida Power Corporation Docket No. ER11-3584-000

ORDER ON RETAIL ADJUSTMENTS TO DEPRECIATION RESERVES

(Issued July 15, 2011)

1. On May 16, 2011, pursuant to section 205 of the Federal Power Act (FPA),[1] Florida Power Corporation (Florida Power) filed to reflect the impact of retail rate depreciation reserve[2] adjustments on Florida Power's Open Access Transmission Tariff (OATT) formula rates. In this order, we reject the adjustments and instead direct Florida Power to account for the retail rate adjustments as regulatory assets, as discussed below.

I. Background

2. On February 28, 2011, in Docket No. ER11-2584, the Commission issued an order accepting Florida Power's proposed depreciation rates included in Schedule 10 of Florida Power's OATT.[3] These depreciation rates were the same as those approved by the Florida Public Service Commission (Florida Commission) in 2010.[4] Protestors in Docket No. ER11-2584 argued that Florida Power should be required to supplement that filing to

[1] 16 U.S.C. § 824d (2006).

[2] As used here, the term "depreciation reserve" refers to amounts recorded in Florida Power's Account 108, Accumulated Provision for Depreciation of Electric Utility Plant.

[3] *Florida Power Corp.*, 134 FERC ¶ 61,145, at P 3 (2011) (February 28 Order).

[4] *In re: Petition for Increase in Rates by Progress Energy Florida, Inc.*, Docket No. 090079-EI, at 45-46 (Fla. Pub. Serv. Comm'n Mar. 5, 2010 and June 18, 2010).

reflect the Florida Commission's approval of adjustments necessary to eliminate theoretical depreciation reserve imbalances (excess depreciation reserves).[5] They argued that those adjustments will have a wholesale rate effect beyond that included in Florida Power's filing. Florida Power argued, however, that the actual quantitative rate impact of those adjustments would not be available for Commission consideration until April 2011, after it filed its 2010 FERC Form No. 1.[6] The Commission agreed with the protestors that, consistent with Order No. 618,[7] additions or deductions to depreciation expense to reflect any theoretical reserve amortization would require an FPA section 205 filing because such amortization would affect the remaining life calculations typically used to determine subsequent depreciation rates.[8] The Commission emphasized that it was only approving the proposed depreciation rates and not any adjustments to eliminate the theoretical depreciation reserve surplus.[9] Florida Power committed to make a FPA section 205 filing to account for these adjustments after its FERC Form No. 1 data became available and before filing its 2010 Annual Update for its OATT formula rate.

II. Florida Power's Filing

3. In the instant filing, Florida Power submits the 2010 impact of the retail depreciation reserve adjustments on its OATT formula rate. Florida Power states that it reduced the cost of removal portion of its depreciation reserve for production and distribution accounts, pursuant to Florida Commission orders and a retail Stipulation and Settlement Agreement dated May 10, 2010 that was accepted by the Florida Commission.[10] This Settlement Agreement states in part:

> [Florida Power] will have the discretion to reduce depreciation expense (cost of removal) by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining

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[5] The theoretical depreciation reserve balance is "the calculated balance that would be in the reserve if the life and salvage estimates now considered appropriate had always been applied." *Id.*

[6] FERC February 28 Order, 134 ¶ 61,145 at P 12.

[7] *Depreciation Accounting*, Order No. 618, FERC Stats. & Regs. ¶ 31,104, at 31,695, n.25 (2000) (Order No. 618).

[8] FERC February 28 Order, 134 ¶ 61,145 at P 20.

[9] *Id.*

[10] Transmittal Letter, Attachment 1 at 3 (Settlement Agreement).

> balance in 2012 during the term of this Agreement until the earlier of (a) [Florida Power's] depreciation (cost of removal) reserve reaches zero, or (b) the term of this Agreement expires. In the event [Florida Power] reduces depreciation expense (cost of removal) by less than the caps set forth in this paragraph, [Florida Power] may carry forward (i.e. increase the cap by) any used depreciation (cost of removal) reserve amounts in subsequent years during the term of this Agreement.[11]

Because the Settlement Agreement grants Florida Power discretion to reduce depreciation expense up to a specified amount in 2010, 2011, and 2012, Florida Power asserts that it does not know whether and to what extent the adjustments to depreciation reserves will impact the OATT formula rate for service in 2011 and 2012.[12]

4. Florida Power states that it has recorded total 2010 depreciation reserve reductions of $65,840,613, consisting of a $33,296,538 reduction to the production plant depreciation reserve and a $32,544,075 reduction to its distribution plant depreciation reserve.[13] These depreciation reserve reductions result in reduced amounts of allocated deferred income taxes attributable to wholesale rate base and, consequently, result in a wholesale rate increase of $79,986 under the OATT formula rate for 2010.[14]

5. Florida Power further explains that it implemented the retail depreciation reduction for 2010 effective January 1, 2010. Accordingly, Florida Power requests waiver of the Commission's prior notice requirements to permit an effective date of January 1, 2010.[15] In support of this waiver, Florida Power explains that, on June 1, 2011, it will complete its Annual Update and true up of the OATT formula rate for 2010 transmission service, and that such true up will be completed using the 2010 FERC Form No. 1 data, which incorporates the depreciation adjustments described in this filing. Therefore, Florida Power is implementing the depreciation adjustments consistent with the OATT formula

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[11] *Id.*

[12] *Id.* at n.8.

[13] *Id.* at 3.

[14] *Id.* The depreciation reserve is an offset to plant in service. Therefore a decrease in reserve results in an increase in rate base.

[15] *Id.* at 4.

rate. Florida Power notes that the Commission has granted waiver of its notice requirements in several similar cases.[16]

III. Notice of Filing and Responsive Pleadings

6. Notice of Florida Power's filing was published in the *Federal Register*, 76 Fed. Reg. 30,330 (2011), with interventions or protests due on or before June 6, 2011. Timely motions to intervene were filed by Florida Municipal Power Agency and Seminole Electric Power Cooperative, Inc.

IV. Discussion

A. Procedural Matters

7. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

B. Substantive Matters

8. As explained below, the Commission finds that Florida Power's adjustment of its depreciation reserves is not in accordance with the Commission's accounting and reporting requirements. We also find that Florida Power must recognize the economic effects of the Florida Commission's rate actions as regulatory assets in Account 182.3, Other Regulatory Assets, rather than as adjustments to its depreciation reserve.

9. In Order No. 618 and in the February 28 Order, the Commission stated that the cost of property used in utility operations should be allocated in a "systematic and rational manner" to periods during which the property is used in utility operations, i.e., over the property's remaining estimated useful service life.[17] For this reason, changes in asset depreciation estimates, including cost of removal, should be made prospectively over the

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[16] *Id.* (*citing South Carolina Electric and Gas Co.,* 132 FERC ¶ 61,043 (2010); *Duke Energy Carolinas, LLC,* 130 FERC ¶ 61,079 (2010)).

[17] *See* FERC February 28 Order, 134 ¶ 61,145 at P 19; Order No. 618, FERC Stats. & Regs. ¶ 31,104 at 31,694-95. Additionally, the Commission's Uniform System of Accounts provides, in part, that, "[u]tilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the <u>*service value*</u> of depreciable property to the service life of the property." General Instruction No. 2, Depreciation Accounting, 18 C.F.R. Part 101 (2011) (emphasis added). "Service value" refers to "the difference between original cost and net

(continued…)

asset's remaining life. Florida Power proposes to adjust its depreciation reserves by $65,840,613 in 2010 and intends to adjust its depreciation reserves by varying amounts in 2011 through 2013 rather than allocating the excess depreciation reserves over the remaining service lives of the related utility plant. While these adjustments may be acceptable for retail ratemaking purposes, they do not conform to our requirements for allocating the costs of utility plant over their service lives. Accordingly, we will direct Florida Power to reinstate all such adjustments to its depreciation reserves (Account 108). Florida Power must also re-file its 2010 FERC Form No. 1 to reflect the restatement of its depreciation reserves. Additionally, because Florida Power's OATT Formula Rate automatically incorporates the revised plant amounts, we will direct Florida Power to recalculate wholesale formula rate billings[18] to reflect the reinstatement of the depreciation reserves and refund with interest all amounts improperly collected from wholesale customers.

10. Additionally, we find that the adjustments approved by the Florida Commission should be recognized in Florida Power's accounts and FERC Form No. 1 financial statements as regulatory assets. The Commission's Uniform System of Accounts for public utilities provides for the use of regulatory assets and liabilities to account for, *inter alia*, rate actions of regulatory agencies that differ from the Commission's accounting requirements.[19] Specifically, Account 182.3, Other Regulatory Assets, provides for amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. Therefore, Florida Power must debit Account 182.3 and credit Account 407.4, Regulatory Credits, for the above discussed adjustments that are reflected in its retail rate orders.

The Commission orders:

(A) Florida Power's proposed adjustments to its depreciation reserves are hereby rejected, and Florida Power is hereby directed to reinstate amounts improperly removed from Account 108, as discussed in the body of this order.

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salvage value of electric plant." Definition No. 37, Service Value, 18 C.F.R. Part 101 (2011). The "net salvage value" is the "salvage value of property retired less the cost of removal." Definition No. 19, Net Salvage Value, 18 C.F.R. Part 101 (2011).

[18] Florida Power Corp., OATT, Schedule 10 (1.0.0), Section 1.

[19] *See* Definition No. 31, Regulatory Assets and Liabilities, 18 C.F.R. Part 101 (2011).

(B) Florida Power is hereby directed to record a regulatory asset to record the economic effects of the Florida Commission's retail rate order, as discussed in the body of this order.

(C) Florida Power is hereby directed to refund with interest all amounts improperly collected from wholesale customers, as discussed in the body of this order.

(D) Florida Power is hereby directed to file a refund report with the Commission within 30 days after making the refunds.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 080677-EI
In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.	DOCKET NO. 090130-EI ORDER NO. PSC-10-0153-FOF-EI ISSUED: March 17, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. WADE LITCHFIELD, MITCHELL S. ROSS, JOHN T. BUTLER, BRYAN S. ANDERSON, and JESSICA A. CANO, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420; and
SUSAN F. CLARK., Radey Thomas Yon & Clark, P.A., 301 South Bronough Street, Suite 200, Tallahassee, Florida 32301
<u>On behalf of FLORIDA POWER & LIGHT COMPANY (FPL)</u>.

JOSEPH A. McGLOTHLIN, CHARLIE BECK, PATRICIA A. CHRISTENSEN, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
<u>On behalf of THE CITIZENS OF THE STATE OF FLORIDA (OPC)</u>.

STEPHANIE ALEXANDER, ESQUIRE, Tripp Scott, P.A.., 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
<u>On behalf of the FLORIDA ASSOCIATION FOR FAIRNESS IN RATE MAKING (AFFIRM)</u>

CECILIA BRADLEY, Office of the Attorney General, The Capitol – PL01, Tallahassee, FL 32399
<u>On behalf of the ATTORNEY GENERAL FOR THE CITIZENS OF FLORIDA (AG)</u>

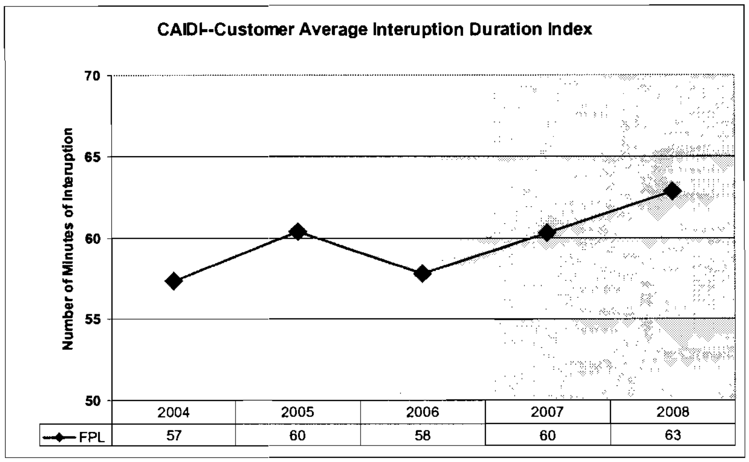

Figure 3. CAIDI

The SAIDI index includes the other indices of SAIFI and CAIDI. SAIDI for FPL's entire distribution system is trending downward. This is a good indication that the length of time a customer experiences an outage is decreasing and in 2008 SAIDI had decreased to 67 minutes.

Based on the above, we find that the quality and reliability of the electric service provided by FPL is adequate. We make this determination based on an analysis of customer complaints, an analysis of the distribution system metrics that include SAIDI, SAIFI, CAIDI, and the analysis of the metrics for the transmission system – System Average Restoration Index (SARI) and SAIDI. We note, however, that outages and momentary power interruptions caused by vegetation do appear to be increasing, and we expect our staff to continue to monitor that trend.

DEPRECIATION STUDY

Capital recovery schedules

Under the capital recovery schedule mechanism, the investment and associated reserve of installations facing near-term retirement are separated out as sub-accounts, and the unrecovered net amounts are amortized over the period of their remaining service to the public. The mechanism is in our depreciation rule, and is the standard practice of this Commission.[7]

FPL's proposed capital recovery schedules address the unrecovered costs associated with the near-term (2010-2013) retirement of the Cape Canaveral and Riviera steam plants, the St. Lucie and Turkey Point nuclear uprate projects, and the meters made obsolete by the new AMI

[7] 2005 Settlement Order; Order No. PSC-99-0073-FOF-EI, issued January 8, 2009, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company; and Order No. PSC-94-1199-FOF-EI, issued September 30, 1994, in Docket No. 931231-EI, In re: Request for change in Depreciation Rates by Florida Power and Light Company.

technology. FPL asserted that the use of capital recovery schedules ensures that recovery of retired equipment occurs close to, or before, their retirement. The proposed recovery period of four years coincides with the period between depreciation studies, and closely matches the remaining period the associated assets will be providing service.

OPC did not dispute the need for capital recovery schedules, but did dispute how the costs should be recovered. OPC witness Pous proposed that: (1) the unrecovered costs associated with the retirement of the Cape Canaveral and the Riviera power plants be offset by a portion of FPL's identified reserve surplus for the steam production investment; (2) the unrecovered costs associated with the nuclear uprates be offset by a portion of FPL's identified reserve surplus for the nuclear production investment; and (3) the unrecovered costs associated with obsolete meters retiring due to AMI technology be offset by a portion of FPL's identified reserve surplus existing in the distribution function. This would eliminate the capital recovery schedule expense and reduce the reserve surplus.

If recovery is not afforded for these identified net unrecovered near-term retirements during their remaining period of service, a negative reserve component will result relating to plant no longer providing service. We agree with OPC that a portion of the reserve surplus can and should be used for the immediate recovery of these costs. This action will reduce the test year depreciation expense as well as the reserve surplus.

SFHHA proposed that: (1) FPL's identified unrecovered costs associated with the near-term planned retiring Cape Canaveral and Riviera facilities should be added to the capital costs of the new repowered generating units; (2) the remaining net book value of the retired nuclear assets should be added to the uprated units for continued depreciation over the lives of those units; and (3) the remaining net book value, including removal costs of the retired meter investment, should be depreciated at the same rate as approved for the meter investment. SFHHA witness Kollen contended that:

- FPL's revenue requirement already includes the cost of advanced meters, so there is no need to accelerate the depreciation of old non-AMI investment;
- FPL's AMI deployment is the cause for the retirements of the existing non-AMI meters; therefore, it is reasonable to reclassify the existing non-AMI meters as a regulatory asset;
- FPL's proposal would require ratepayers to pay for existing non-AMI meter investment and the new AMI meter investment at the same time; and
- Since the existing non-AMI meters will be replaced at one time over a four-year period, FPL's four-year amortization proposal would "double-up" recovery for meters during that period.

FPL witness Davis asserted that he agreed that nuclear uprate costs relating to plant additions should increase the plant investment and be depreciated over the life of the related group of assets. However, witness Davis disagreed that the net book value of the identified nuclear uprate retirements and associated removal costs should be deferred and recovered over

Reserve Imbalance

The theoretical reserve is the calculated balance that would be in the reserve if the life and salvage estimates now considered appropriate had always been applied. The book reserve is the amount actually recovered to date. The difference between the theoretical reserve and the book reserve is a reserve imbalance. If the calculated theoretical reserve is more than the book reserve, the imbalance is a reserve deficit. If the calculated theoretical reserve is less than the book reserve, the imbalance is a reserve surplus.

Applying its proposed depreciation life and salvage parameters, FPL calculated a reserve surplus of $1.245 billion. OPC calculated a reserve surplus of $2.75 billion based on its proposed depreciation formula. The formula for the prospective theoretical reserve is provided in Rule 25-6.0436(4)(k), F.A.C. Using this formula and the life and salvage components approved above, we calculate a reserve surplus of $1,208.8 million, as shown in Table 7 below:

Table 7: Reserve Imbalance	
	($000,000)
Steam Production	353.1
Nuclear Production	127.0
Other Production	119.6
Transmission	12.1
Distribution	555.6
General	41.4
Total Reserve Imbalance	1,208.8

Corrective reserve measures

Having determined above that there is a theoretical reserve surplus, the parties asked us to determine what, if any, corrective measures should be taken. The crux of the parties' dispute was whether the reserve imbalance should be corrected over the remaining life of the assets or over a shorter period of time. FPL argued that the surplus should be addressed through the remaining life rate design of its plant (22 years), rather than "accelerating" the recovery over a short period of time as suggested by the intervenors. FPL contended that the remaining life approach to resolve reserve imbalances is the norm and there is no reason to deviate. OPC, FIPUG, and FRF asserted that the magnitude of the reserve imbalance warranted a corrective approach shorter than the normal remaining life depreciation approach. SFHHA did not address the magnitude of the surplus, but asserted that it should be amortized over a short period of time.

FPL argued that a short amortization of the reserve surplus would have "the direct and unavoidable effect of rapidly increasing rate base, the required return on rate base, and future depreciation expense – all of which will have to be borne by future customers." FPL suggested that a middle path would be to transfer a portion of the reserve surplus to offset the expenses associated with its proposed capital recovery schedules. FPL argued that this action could provide "a measure of shorter-term relief for customers without doing as much damage to regulatory practices and future customers' pocketbooks." AIF supported FPL's position.

While OPC witness Pous calculated a reserve surplus of $2.75 billion using his proposed life and salvage values, he recommended that only FPL's identified reserve surplus of $1.25 billion be amortized over four years. OPC and FIPUG proposed that $314.3 million of FPL's reserve surplus should be first applied to offset the unrecovered costs associated with FPL's proposed capital recovery schedules for near-term retirements. OPC asserted that a four year amortization of the remaining balance of $894.6 million would reduce test year depreciation expense, thereby lowering FPL's revenue requirements. OPC submitted that amortizing the reserve surplus represented the most appropriate remedy to eliminate the intergenerational inequity the surplus created. FRF supported the OPC position that $1.25 billion of the reserve surplus be amortized over four years. SFHHA suggested that we require FPL to amortize its calculated reserve surplus of $1.245 billion over a five-year period. SFHHA asserted that the calculated surplus demonstrated that FPL's past depreciation rates were excessive, considering present expectations regarding depreciation parameters.

FIPUG witness Pollock proposed a slightly different approach to correct the remaining $894.6 million surplus. The witness proposed that FPL continue to record the $125 million annual credit to depreciation expense until the next depreciation study review.

Amortization of the reserve surplus will serve to decrease the reserve over the amortization period, thus increasing rate base. At the time of FPL's next depreciation review, its reserve positions will be lower, thereby resulting in higher depreciation rates, all other things remaining equal. Indeed, OPC recognized that depreciation rates in the instant proceeding are higher due to the lower reserve position resulting from the $500 million depreciation credit the Company recorded during the years 2005-2009, in accord with the 2005 Settlement Order. However, as noted by witness Pous, FPL's calculated theoretical reserve is lower by $500 million.

OPC argued that a reserve imbalance violated the matching principle.[25] The intervenors claimed that the existence of FPL's reserve imbalance indicates that past and current customers have paid more than their fair share of depreciation expenses and that future customers will therefore pay less than their fair share. In contrast, FPL contended that intergenerational inequity concerns are mitigated by the fact that customer rates were not increased during the time when the reserve surplus accumulated.

OPC contended that whether the remaining life methodology was adequate to address reserve imbalances depended on the magnitude of the imbalance and the time frame over which it would be corrected. The relative adequacy of the reserve causes the remaining life rate formula to self-adjust for historic over- or under-recovery, as well as for changes in projected life or salvage parameters. A reserve imbalance indicates a failure of the matching principle. The

[25] The matching of the period of time over which depreciation expense is collected with the service life of the group of assets is called the matching principle. Customers benefitting from the assets should be those who pay for the assets.

depreciation expenses of the past were misstated, so correction should be made now to reduce the misstatement into the future. Correction of the imbalance will result in a return to the matching principle. In this case, OPC argued that FPL's reserve imbalance was so great that recovery over the remaining life (22 years) was inadequate.

We believe that the very presence of a reserve imbalance indicates the existence of intergenerational inequity. Based on what is known today, the life estimates of yesterday are now viewed as being too short. FPL has lengthened the life span estimates for its production plants. Net salvage estimates have changed. This does not mean however, that past life and salvage estimates were wrong. Disregarding the fact that settlements were reached in 2002[26] and 2005[27] that addressed depreciation and many other matters, the last time this Commission actually conducted a thorough review and analysis of FPL's depreciation parameters was in Order No. PSC-99-0073-FOF-EI, issued January 8, 1999, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company. Conditions, Company plans, and regulatory requirements change. OPC witness Pous acknowledged that depreciation parameters change over time simply because depreciation is a projection of anticipated events in the future. FRF recognized in its brief that in a depreciation study review, a goal has been to align the actual and theoretical reserve positions for all accounts.

We agree with FPL witness Deason and OPC witness Pous that it is unlikely there would ever be a time when there is no reserve imbalance, simply because as time passes, more information is known and better estimates of life and salvage can be determined. However, that is not a reason to defer taking some action to correct reserve imbalances, where possible, either through reserve transfers or an amortization. The magnitude of the reserve imbalance should also dictate what action is taken. The matching principle argues for a quick correction of any surplus; the quicker the better so that the ratepayers who may have overpaid would have a chance of benefitting.

We agree with FPL that current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates. If the reserve surplus is reduced, the depreciation reserve will increase, thereby, all things remaining equal, causing depreciation rates and future revenue requirements to naturally increase.[28] At the present time, it can be argued that the current reserve surplus results in prospective depreciation rates that are artificially low. This is the beauty or the beast of the remaining life rate methodology. A surplus means that under present expectations more than enough has been recovered, so there is a smaller amount left to be recovered over the average remaining life. Conversely, the presence of a reserve deficit means that not enough has been recovered to date, so the depreciation rate must increase to make up the difference in the future.

[26] Order No. PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI, In re: Review of the retail rates of Florida Power & Light Company, and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. (2002 Settlement)

[27] Order No. PSC-05-0905-S-EI, issued September 14, 2005, in Docket Nos. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and 050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company. (2005 Settlement)

[28] About $300 million of FPL's current base rate increase is due to the $125 million annual depreciation expense credit that was recorded in accord with the 2005 FPL Rate Case Settlement Order.

The remaining life rate typically carries the burden of correcting any reserve imbalance. A significant reserve imbalance can distort resulting depreciation rates. For example, an account with a 40-year average service life, 20-year average remaining life, zero percent net salvage, and 80 percent reserve would result in an average remaining life rate of 1.0 percent. This is due to the fact that the reserve should theoretically be 50 percent rather than 80 percent. The surplus in the reserve results in a remaining life depreciation rate being lower than it otherwise would be to correct the surplus over the remaining life. If the account reserve is restated to its theoretically correct level, the resulting depreciation rate is 2.5 percent. Thus, the presence of the reserve surplus depresses the resulting depreciation rate from 2.5 percent to 1.0 percent. The more significant the reserve surplus, the more depressed the resulting remaining life rate will be.

The intervenors contended that our past orders support a position that reserve imbalances have historically been recovered over a period of time that is shorter than the average remaining life. FPL, on the other hand, contended that the orders referenced by the intervenors are not applicable to FPL's circumstances. FPL witness Davis also asserted that none of the actions in the referenced orders had any impact on customer rates.

In the 1990s, we allowed FPL to record additional depreciation expense to reduce the potential for stranded investments. In 1995, we authorized FPL to record $126 million in additional depreciation expenses to the reserve for nuclear production. Also, for 1996 and 1997, we permitted FPL to record an additional $30 million in expense to the reserve for nuclear production, and to record an additional depreciation expense based on differences between actual and forecasted revenues.[29] We allowed FPL to continue the recording of these additional expenses in 1998 and 1999 by Order No. PSC-98-0027-FOF-EI.[30] We found that it was good regulatory policy to eliminate these types of items when the funds are available to do so without raising customer rates.

Subsequently, in the FPL 1999 Revenue Sharing Agreement approved by Order No. PSC-99-0519-AS-EI, we granted FPL, among other things, the discretion to record up to $100 million of additional depreciation expense each year of the three-year settlement period to reduce nuclear and/or fossil production plant in service.[31] As part of this settlement, customer rates were reduced by $350 million and a revenue cap and revenue sharing plan was established.

As a result of the FPL 2002 Settlement, approved in Order No. PSC-02-0501-AS-EI, FPL received the discretionary ability to record a depreciation expense credit of up to $125 million annually for 2002-2005.[32] The amounts recorded first went to offset the $170.3 million bottom

[29] Order Nos. PSC-95-0672-FOF-EI, issued May 31, 1995, and PSC-96-0461-FOF-EI, issued April 2, 1996, in Docket No. 950359-EI, In re: Petition to establish amortization schedule for nuclear stranded investment by Florida Power & Light Company.

[30] Order No. PSC-98-0027-FOF-EI., issued January 5, 1998, in Docket No. 970410-EI, In re: Proposal to extend plan for recording of certain expenses for years 1998 and 1999 for Florida Power & Light Company.

[31] Order No. PSC-99-0519-AS-EI, issued March 17, 1999, in Docket No. 990067-EI, In re: Petition by the Citizens of the State of Florida for a full revenue requirements rate case for Florida Power & Light Company.

[32] Order No. PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI, In re: Review of the retail rates of Florida Power & Light Company, and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. (2002 Settlement)

line amortization recorded pursuant to Order No. PSC-99-0519-AS-EI, with any additional amounts recorded to a bottom line reserve to be allocated to specific accounts in the next FPL depreciation study after the term of the settlement. Among other things, the settlement reduced FPL's customer rates by $250 million and continued a revenue cap and revenue sharing plan. FPL acknowledged that it had overdepreciated its plant and a depreciation expense credit offered through the settlement would help correct the situation.

In the 2005 Settlement Order, FPL was again authorized to amortize up to $125 million annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve for years 2006-2009.[33] FPL recorded $500 million in accord with the agreement.

FRF argued in its brief that our declared policy with respect to reserve imbalances is to correct them as soon as possible without adversely impacting a company's ability to earn a fair and reasonable return.[34] FRF noted that we have also targeted overearnings in the past to book additional depreciation expense, thereby lowering reported earnings and bringing them in line with the allowed rate of return. In the instant proceeding, we are setting a new rate of return for FPL. In deciding whether to amortize the reserve imbalance as the intervenors proposed, we should also consider any negative impacts such an amortization would have on FPL's financial integrity.

OPC's proposed adjustment to address the reserve imbalance would reduce FPL's revenue requirement by approximately $311 million per year. Because rate base would be higher as a result of this adjustment, the reduction to FPL's cash flow would be offset by approximately $20 million of additional return earned on this incremental rate base. Thus, the net impact of the proposed adjustment would be a reduction to cash flow of approximately $291 million.

FRF asserted that OPC's proposed amortization would not deny FPL recovery of any capital dollars, but would only affect the timing of the collection of those dollars. Further, FRF argued that OPC's proposed amortization would not affect FPL's earnings or earned rate of return. FRF stated that metrics used to analyze financial integrity generally include measures of debt, cash flow, and interest coverage requirements.

FRF asserted that the coverage ratios (the number of times FPL's generated cash flow covers debt service) were important indicators of financial integrity. FRF stated that FPL's financial strength is such that FPL's cash flow would be sufficient to amortize $1.25 billion of the reserve surplus identified by OPC witness Pous and maintain coverage ratios that warrant an "A" rating by Standard & Poors (S&P).

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[33] Order No. PSC-05-0905-S-EI, issued September 14, 2005, in Docket Nos. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and 050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company. (2005 Settlement)

[34] Order No. PSC-01-2270-PAA-EI, issued November 19, 2001, in Docket No. 060699-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities, p. 2.

The financial metrics affected by the proposed adjustment are the cash from operations to interest ratio (CFO/Interest) and the cash from operations to debt ratio (CFO/Debt). The debt to total capital ratio is unaffected by the proposed adjustment. FPL's corporate credit rating is single A flat from S&P, single A1 from Moody's Investor Service (Moody's), and single A flat from Fitch Ratings (Fitch). Pursuant to S&P's rating methodology, FPL's business profile is rated as excellent and its financial profile is rated as intermediate. Based on these designations, the ratings criteria published by S&P and Moody's for FPL's current credit ratings include the following cash flow metric standards.

Table 8

	S&P A rating	Moody's A rating
CFO/Interest	3.0x – 4.5x	4.5x – 6.0x
CFO/Debt	25% – 45%	22% – 30%

OPC witness Lawton testified that, while the proposed adjustment to address the reserve imbalance will decrease FPL's cash flow metrics, he did not believe it will harm the Company's financial integrity. Witness Lawton demonstrated that FPL's CFO/Interest ratio will decrease from 6.7x to 5.9x and the Company's CFO/Debt ratio will decrease from 45 percent to 40 percent. That said, this analysis does not take into account additional adjustments that will impact cash flow. However, witness Lawton argued that even if all of OPC's proposed adjustments were made, there is no basis to conclude that FPL's credit rating would fall below investment grade. FPL witness Pimentel agreed that even a two-notch downgrade for FPL would still result in a triple B plus rating, which would remain firmly investment grade. Moreover, none of the rating agencies have indicated that they would downgrade FPL's credit rating even if we denied the entire rate increase.

In this case, FPL's net reserve imbalance is a $1.2 billion surplus. The reserve surplus is of such a magnitude that its existence results in abnormal depreciation rates. Where significant reserve surpluses and deficits exist, corrective reserve transfers between accounts or amortization of the reserve imbalance should be considered. Whether the reserve imbalance is a surplus or a deficit, it violates the matching principle and represents a subsidy, and thus should be corrected.

As mentioned above, we calculated a theoretical reserve for each account within each production unit, and each transmission, distribution, and general plant account. Comparing the theoretical reserve to the book reserve resulted in various account surpluses and deficits that we netted to a bottom-line reserve surplus amount of $1.2 billion. As a result of this netting, each account's reserve is placed at its theoretically correct position. The theoretically correct reserve position is reflected in the depreciation rates contained in Table 3 and Table 6 above.

FPL, FIPUG, and OPC suggested that we transfer a portion of the reserve surplus to offset the expenses associated with its proposed capital recovery schedules. We agree. Accordingly, $314.2 million of the reserve surplus shall be transferred to offset the unrecovered costs associated with FPL's proposed capital recovery schedules. This reduces the reserve imbalance to an $894.6 million surplus.

FPL argued that amortization of the remaining reserve surplus over any time period other than the remaining life results in intergenerational unfairness to the ratepayers of yesterday versus those of tomorrow. OPC, on the other hand, argued that the existence of a reserve imbalance indicates that there are intergenerational inequities in that current and past customers paid more than they should have, thereby subsidizing future customers. We agree with OPC's position that intergenerational unfairness already exists, as witnessed by the existence of such a significant reserve imbalance. Therefore, we are of the opinion that amortizing the remainder of the reserve surplus is the most appropriate remedy to eliminate the intergenerational inequity the surplus created. The only question remaining is how long it should take to correct the situation.

Accordingly, we find that the remaining reserve surplus amount of $894.6 million shall be amortized over a four-year period. This is consistent with our policy with respect to reserve imbalances, which has been to correct them as soon as possible without adversely impacting the company's ability to earn a fair and reasonable return.[35] We find that there is substantial evidence in the record to show that the company's ability to earn a fair and reasonable return will not be adversely affected. Furthermore, our decision is consistent with past orders in which we have amortized reserve imbalances over periods shorter than the remaining life.[36] And we note that we will be reviewing FPL's depreciation reserve again when FPL files its next depreciation study.

In conclusion, each account's book reserve shall be brought to its calculated theoretically correct level. Of the $1,208.8 million bottom-line reserve surplus, $314.2 million shall be used to offset the unrecovered costs associated with the capital recovery schedules of near-term retiring investments. The remaining reserve surplus of $894.6 million shall be amortized over a 4-year period, beginning January 1, 2010. As part of FPL's next depreciation study, to be filed no later than March 16, 2013, FPL's reserve position will be reviewed and assessed for any other necessary action.

Implementation date for revised depreciation rates, capital recovery schedules and amortization schedules

FPL proposed an implementation date of January 1, 2010. All the parties, except SFHHA, agreed with FPL's proposed implementation date. SFHHA argued that the implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules should correspond with the implementations of rates resulting from this proceeding. We disagree with SFHHA's proposed implementation date. The implementation date for the

[35] Order No. PSC-01-2270-PAA-EI, issued on November 19, 2001, in Docket No. 010699-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities, p. 2.

[36] Order No. PSC-96-0461-FOF-EI, issued on April 2, 1996, in Docket No. 950359-EI, In Re: Petition to establish amortization schedule for nuclear generating units to address potential for stranded investment by Florida Power & Light Company; Order No. PSC-06-0307-FOF-TP, issued April 20, 2006, in Docket No. 041269-TP, In re: Petition to establish generic docket to consider amendments to interconnection agreements resulting from changes in law, by BellSouth Telecommunications, Inc.; and Order No. PSC-98-1723-FOF-EI, issued on December 18, 1998, in Docket No. 971570-EI, In re: 1997 Depreciation Study by Florida Power Corporation.

Depreciation Systems

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Preface

THIS book grew from our recognition of the need for a systematic explanation of depreciation using simple, easy-to-follow illustrations. In particular, we examine the portion of depreciation that relates to accounting, specifically as found in public utilities. However, many of the topics covered relate to other applications of depreciation, including valuation of property and taxation. Several conceptual difficulties surround depreciation. One is the lack of understanding that the determination of depreciation involves an intricate system comprising most aspects of the operation of a company. Another is the tendency to view components of the system as being independent of one another. Finally, the use of complicated arithmetic examples, frequently requiring lengthy, time-consuming calculations when explaining ideas, distracts the reader and obfuscates the idea being illustrated.

Asset management includes four actions: (1) the decision, based on analysis of the associated costs and revenues, to acquire property; (2) its acquisition, installation, and associated accounting; (3) its use and related accounting, including the proration of capital expenses to each accounting period; and (4) its retirement and associated accounting. Each action interacts with the other. As management decisions are often based on information from these accounting records, it is essential to exercise careful control over the annual and cumulative results of the depreciation system. This means that the methods used to make estimates of the variables used in calculating and adjusting depreciation should be scrutinized, because they significantly affect the management of the assets of the company.

Investments in capital assets, such as a turbine used to turn an electri-

Table 4.10. Conversion of salvage in Table 4.9 to 1982 dollars.

	Experience year						
	82	83	84	85	86	87	88
Gross salvage	94	337	418	645	834	890	720
Cost of retiring	27	106	163	276	437	539	553
Annual retirements	157	627	941	1568	2508	3135	3292
Gross salvage ratio	.60	.54	.44	.41	.33	.28	.22
Cost of retiring ratio	.17	.17	.17	.18	.17	.17	.17
Net salvage ratio	.43	.37	.27	.23	.16	.11	.05

5 Depreciation Systems

THE recovery of capital through depreciation accruals may be thought of as a dynamic system. A system is an arrangement of things that are connected to form a complete organization of integrated parts. The state of the system at any time is defined by current values of the characteristics that define the system. A dynamic system is one where the state of the system depends on the history of the input variables. To define and study a system is to better understand the system so that more efficient methods of control can be designed to accomplish the desired ends.

There are two methods of controlling a system. One is to select an input and wait for the result or final output. If a different output is desired, the input is changed and the new output is obtained. The other method of control is to select an initial input, monitor the process, and when necessary, alter the input to achieve the desired goal. The first method is called an open control loop and the second a closed control loop. A necessary feature of the closed control loop is the feedback resulting from the monitoring of the system. A home heating system is a common and simple example of a dynamic system with a closed feedback loop. The parts of the system are a furnace and a thermostat. The thermostat monitors the room temperature and creates feedback, in the form of electrical signals, when the room temperature rises above or falls below the desired temperature. The electrical signals turn the furnace off or on to achieve the desired goal, a constant, predetermined room temperature.

Think of a depreciation accounting system as a dynamic system controlled with a closed feedback loop. Estimates of life and salvage and the amount of plant in service are inputs to the system, and the accumulated provision for depreciation is a measure of the state of the system at any time. The process of calculating the accumulated provision for depreciation is determined by the factors needed to define the system. The initial input to the system is estimates of the life and salvage, which are combined in an accrual rate. Dynamic forces affect the life and salvage, and revision of the original life and salvage estimates are the result of the monitoring process. These revisions to the initial input initiate feedback in the form of adjustments to the accumulated provision for depreciation. The goal of the system is recovery of capital in a timely manner.

One consideration that complicates this discussion is that many options can be combined to form many different depreciation systems. Whether the depreciation is for book, tax, valuation, or other purposes, each of these factors must be considered when discussing and defining a depreciation system.

DEFINING A DEPRECIATION SYSTEM

Below is a list of the factors needed to define a depreciation system. Each factor contains two or three options, and the complete definition of a system requires the selection of one option from each factor. The order of the list is arbitrary, but the last four factors are those whose options are varied when discussing depreciation systems commonly used to calculate book depreciation.

1. The depreciation concept, including (a) physical condition, (b) decrease in value, or (c) cost of operation
2. Depreciation over (a) time or (b) units of production
3. Depreciation of (a) a unit of property or (b) a group of property
4. Methods of allocation, including (a) the straight line method, (b) an accelerated method, or (c) a decelerated method
5. Procedures for applying the method of allocation including (a) the average life procedure, (b) the equal life group procedure, or (c) the probable life procedure
6. Adjustment using (a) the amortization method or (b) the remaining life method
7. Use of (a) the broad group model or (b) the vintage group model

The mathematically astute reader who multiplies the number of options in each factor will find that there are 432 combinations of options, each of which is a potential depreciation system. However, not all of these combinations are feasible, and some are unimportant. Only a few of these

combinations are of major interest when considering systems of book depreciation currently being used.

Concepts of Depreciation

Three options are available when defining the concept of depreciation. These include (a) physical condition, (b) decrease in value, or (c) cost of operation. Though all have been used by utilities to determine book value, the cost of operation is, with few exceptions, the concept in current use.

Physical condition is, perhaps, the first option a lay person would think of if asked to define depreciation. An early reference to the relationship between depreciation and physical condition is from the 1588 textbook by John Mellis who referred to a debit to the profit and loss account because "implements of householde I doe find at this day to be consumed and worn." A later reference is in the 1833 annual report of the Baltimore and Ohio Railroad, which reported that an annuity was established "to provide for the replacement of oak sills and sleepers and yellow pine stringpieces."

Two problems arise when using the concept of physical condition as a measure of depreciation. First, wear and tear do not account for all retirements; in fact, they are often a minor reason for the retirement of property. Second, physical condition can be difficult to measure. Though it is possible to measure directly the wear of railroad track and the corrosion of cast iron pipe, easily measurable wear is not characteristic of most industrial property.

The concept of loss of value is also a common depreciation concept, and the lay person often uses it to explain the difference between the purchase price and the current market value of an automobile or major household appliance. The definition from the Supreme Court case *Lindheimer v. Illinois Bell Telephone* (1934) is often quoted: "Broadly speaking, depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence."

In contrast to the concept of physical depreciation, the Lindheimer definition recognizes that factors other than wear and tear cause or contribute to the retirement of property. The definition refers to the "loss" but does not clearly state what is "lost" or how the "loss" should be measured. A 1935 definition by the Federal Communications Commission was similar to the Lindheimer definition but referred to "loss in service value," where service value is equated to the original cost less salvage.

Use of the concept of loss of value to determine annual depreciation charges might imply the need for an annual valuation of the property owned by the organization, particularly if the rate of loss in value was not uniform or readily defined. The process of determining a value is complex, depending on the purpose of the valuation and type of property. Thus, an annual valuation of a utility could be such an expensive and time-consuming process that it would not be a practical approach to use in determining annual depreciation.

Many types of property provide a constant level of service until they are retired. The intrinsic physical value of this type of property is only that it functions. A gas meter is a common example of a type of property that may provide a constant level of service throughout its life. If value is measured by the level of service provided, the meter would retain full value until retirement because its value to the utility would depend on its function rather than its age. This concept ignores the consumption of future service and would result in an annual depreciation charge that would be zero until the final year of service. Then the charge would equal the full value and would result in deferring all depreciation charges until the final year of service. A concept that better matches depreciation to service rendered and weighs it in relation to the total service potential might be preferable for purposes of both book and valuation depreciation. That is, a quantitative measure of value, such as service-years, is generally preferable to a functional measure.

The third concept is that depreciation represents an allocated cost of capital to operation. This concept recognizes that depreciation is a cost of providing service and that an organization should recover the capital invested in equipment and other property needed to provide the required service. In fact, the term *capital recovery* is often used in connection with depreciation. An early reference to depreciation is by the Roman Marcus Vitrurius Pollio, who in 27 B.C. wrote of "walls which are built of soft and smooth-looking stone, that will not last long." He calculated that the walls would not last more than eighty years and suggested that, for purposes of valuation, one-eightieth part of their original cost be deducted each year. Pollio not only raised several issues concerning depreciation but seemed to be equating depreciation to a cost of operation.

The definition of *depreciation accounting* by the American Institute of Certified Public Accountants (1961, par. 56) reflects the concept of depreciation as a cost: "Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation." This definition does not use the term *loss of service value* because it is defining depreciation accounting rather than depreciation itself. The definition emphasizes that the purpose of depreciation accounting is a means of distributing cost in a rational manner during the service life, in turn providing for the systematic recovery of capital. By use of the term *useful life,* the definition encompasses all causes of retirement. By referring to the distribution of cost less salvage, this definition recognizes that salvage should be considered when developing depreciation charges.

Historically, all three concepts of depreciation have been used by utilities to determine the book value of industrial property. Of these, the concept of depreciation as the allocation of cost has proven to be the most useful and most widely used concept.

Time versus Unit of Production

Useful life can be measured in units of time or units of production (also called units of service). Measurement of life in years is a common and familiar concept. Measurement of life in units of production can be applied to some types of property such as a truck, whose life can be measured in miles (e.g., a useful life of 100,000 miles). A feeder pipeline connecting an oil field to a transmission line will be in service until the field is no longer productive. If the only function of the feeder line is to transport oil from the field to the transmission line, the life of the feeder line is determined by the reserves of the oil field that must eventually pass through the pipeline. Annual depreciation could be measured in units of production, such as barrels of oil. A railroad might depreciate rail as a function of the accumulated weight that the rail has carried.

Suppose a truck is to be depreciated over its life as measured in miles. First, the life must be estimated, say 100,000 miles. Second, the number of miles the truck will be driven during the next year, say 27,000 miles, must be forecast to have sufficient information to budget the annual depreciation charge. Third, at the end of the year when the budgeted annual depreciation becomes an accounting entry, the amount would be calculated to reflect the actual miles driven.

The most common measure of life is in units of time rather than units of production. Most types of property (e.g., poles, buildings, wire) do not have a measure of production associated with them. If the life can be measured in some unit of production and the rate of production is constant from year to year, measurement of life in either units of time or production will result in the same annual accruals. The unit of production has strong appeal in situations where use varies significantly over time and the life can be measured in units of production. But these two conditions are not often met, and usually life is measured over time.

Depreciation of an Individual Unit versus a Group

Accounting records of transactions relating to depreciable property can be kept on either a unit or a group basis. An individual unit of property has a single life, while the units in a group of property display a range, or dispersion, of lives. Grouping many units of property into a single account simplifies the accounting system but also creates a complexity not encountered in the depreciation of an individual unit. The resulting complications provide a major challenge to the depreciation analyst.

A vintage group refers to a group of property placed in service during the same year. The plant in service decreases until all units are retired from service. The individual unit and the vintage group are similar because each has well-defined life characteristics. The life of an individual unit is described by a single number and the life of a vintage group is described by a survivor curve, which is a statistical description of the lives of the units of property in the group.

Methods of Allocation

To fully recover capital invested in plant and equipment, the total depreciation charge must equal the depreciation base. When using the allocation of cost concept, the depreciation base is the initial, or original, cost less net salvage. The annual depreciation accrual rate for a unit of property can be (a) constant over life (straight line), (b) high during early years and low in later years (accelerated), or (c) low in early years and high in later years (decelerated). Most methods of allocation fall into one of these three classifications, although it would be possible to develop a method that is a combination of them. The straight line method of allocation is the method of allocation most often used when calculating book depreciation. Accelerated methods of allocation are commonly used for tax purposes. Decelerated methods of allocation are not in common use for book or tax purposes, but they are of historical interest and are used in valuation problems.

Average Life, Equal Life Group, or Probable Life Procedures

The average life and equal life group procedures are two ways of applying a method of allocation to determine the annual accrual. The probable life procedure is similar to the average life procedure, but is not appropriate for depreciation accounting.

A group of property displays a wide range of lives, and the life characteristics of the group must be described statistically. This is in contrast to a unit of property, whose life can be described as a single number. When depreciating a group of property, rather than a unit of property, a major decision must be made whether to base the depreciation accrual rate on the average life of the group (the average life procedure) or whether to divide the group into subgroups of equal life (the equal life group procedure).

In the average life procedure, a constant annual accrual rate based on the average life of all property in the group is applied to the surviving

property. Most retirements occur either before or after, rather than at, the average life, but both short- and long-lived property are depreciated at the same rate. Property having a shorter life than the average will not be fully depreciated by the time of its retirement. Because the accrual rate is based on the average life of the group, the difference between accruals for early retirements and the full cost of the early retirements will be balanced during the life of the property having lives longer than the average. The result is that the group will be fully depreciated by the time of the final retirement.

In the equal life group procedure the property is divided into subgroups that each have a common life. Each subgroup is then depreciated as a unit using an accrual rate based on the common life of the group. Each unit is fully depreciated by the time it is retired. Application of the equal life group procedure is generally considered to better match the consumption of capital with service provided than does application of the average life procedure.

Any of the three methods of allocation (i.e., straight line, accelerated, or decelerated) can be applied to an individual unit or to group property. When the average life procedure is applied, the straight line method of allocation is easily used; application of either an accelerated or a decelerated method becomes more complicated. When the equal life group procedure is used, any of the three methods of allocation can be easily used.

The probable life procedure is a variation of the average life procedure. It is not valid for depreciation accounting or capital recovery because it does not fully depreciate the group. The depreciation charges are allocated over the average life of the property remaining in service (i.e., over the probable life), so that the continually decreasing rate is inadequate to fully recover the depreciable base. Use of this procedure should be restricted to those special situations where it is applicable; for example, it may used in the valuation process.

Methods of Adjustment

Depreciation accrual rates are calculated using estimates of the service life and salvage. Over time, new events that provide additional information occur, and the existing estimates are revised. A revision of the estimates of life and salvage results in the recognition that the accumulated provision for depreciation may now be either higher or lower than necessary, depending upon the magnitude and direction of the revised estimates. This recognition may justify an adjustment to the accumulated provision for depreciation, an adjustment to the annual depreciation rate, or both.

Adjustments to the accumulated provision for depreciation[1] can be made using either a fixed amortization period or the remaining life basis. The term *amortization method of adjustment* is used to describe a general approach in which the first step is the estimation of the required adjustment to the accumulated provision for depreciation and the second step is the determination of the timing and amount of the adjustment. In the remaining life method of adjustment, adjustments to the accumulated provision for depreciation are amortized over the remaining life of the property and are automatically included in the annual accrual.

The amortization method of adjustment uses the revised estimates of life and salvage characteristics to compute the calculated accumulated depreciation (CAD) to serve as a guide when determining the appropriate adjustment. The CAD is compared to the accumulated provision for depreciation; a significant difference between the two shows that an adjustment to the accumulated provision for depreciation may be advisable. The adjustment can be allocated in several ways, which might include (1) a lump sum equal to the adjustment made immediately, (2) amortization of the adjustment over a fixed period (e.g., over 5 years), or (3) amortization of the adjustment over the remaining life of the property. A lump sum adjustment is not an amortization but will be considered an option in the amortization method of adjustment (i.e., the amortization method could be more accurately called the amortization or lump sum method of adjustment). The difference between the CAD and the accumulated provision for depreciation is only an estimate of the required adjustment. The need for, the magnitude of, and the timing of the actual adjustment should be based upon the recommendation of the depreciation professional. This recommendation requires professional judgment and should consider several factors: the characteristics of the account; the cause of the difference; estimates of future events that will affect the property; the year-to-year volatility of the accumulated provision for depreciation; and the depreciation policies of the organization. A revised forecast of life or salvage normally leads to a revised depreciation rate even when an adjustment to the accumulated provision for depreciation is not considered necessary.

When using the remaining life method of adjustment, emphasis is placed upon forecasting the remaining life of the property in service. A change in the estimate of either life or salvage characteristics automatically triggers an adjustment to the accumulated provision for depreciation, and the adjustment will be spread over the remaining life of the property.

Broad Group or Vintage Group Model

Typically, property depreciated as a group provides a service to the organization over a long period of time. Each year property in the group is retired from service, but new property is added to the group to replace that retired or to increase the capacity of the group. Thus, over time vintage groups are continually being retired from and added to the group. A group

such as this is called a *continuous property group*, though the term *open-ended group* is also used. The life and salvage characteristics of the vintages in the continuous property group must be specified in some systematic manner. The broad group model views each vintage in the continuous group as having identical life and salvage characteristics. The vintage group model views each vintage as having different life and salvage characteristics.

UNIT DEPRECIATION

Depreciation of a unit of property is a concept more readily understood than depreciation of a group of property. This section will present a brief discussion of the three methods of allocating the depreciable cost of a unit of property among accounting periods. An understanding of unit depreciation, particularly the straight line method of allocation, is necessary when considering depreciation for a group of property. In all examples, the cost of operation depreciation concept will be used, and depreciation will be over time (i.e., years). The depreciation base will equal the original cost less net salvage. This base represents the amount of capital to be consumed and, therefore, the amount of capital to be recovered through depreciation accruals.

Methods of Allocation

The three general methods of allocation are straight line, accelerated, and decelerated. An example of each will be applied to a unit of property that has an initial cost of $4000, a life of 4 years, and a net salvage value of $800 at retirement. The net salvage is commonly expressed in terms of the *salvage ratio* (SR), $800/$4000 or 0.20 or 20%.

Straight Line Method of Allocation

The straight line method of allocation is used almost exclusively by regulated, capital-intensive companies when calculating depreciation accruals for book accounting purposes. The straight line method applies a constant annual accrual rate to the cost of the unit, thus yielding a constant annual depreciation charge. The net book value (i.e., the original cost less the accumulated provision for depreciation) plotted versus time is a straight line.

The straight line rate is (1 − SR)/life. The factor (1 − SR) = (1 − 0.20) = 0.80, or 80%, represents the fraction of the original investment consumed during the life of the property, or the depreciable base. In this example that amount is 0.80 × $4000, or $3200. The accrual rate is 0.80/4

9. This average was found by averaging the beginning of year and end of year balances. This assumes the survivor curve segment is a straight line during the age interval. A more accurate method is to use the table value of the percent surviving at the midpoint of the age interval.

10. The area under the curve in Figure 6.3 is measured in percent-years and must be divided by 100% to convert to years.

11. The percent retired for each ELG interval will be adjusted by a factor of 73.02/69.86 or 1.045. The percent surviving at each age will be adjusted by the same factor. When the accrual for the age interval is divided by the average percent surviving, the adjustments cancel each other and the resulting rates are the same as shown in Table 6.15.

7 Defining Depreciation Systems

THIS chapter will define terms commonly used to describe depreciation systems. There is no single source of standard definitions of depreciation systems. Several terms have been commonly used to express the same meaning, and sometimes a term may have multiple meanings, depending on the user or the context in which it is used.

The field of depreciation is small and fragmented. It includes capital-intensive enterprises such as public utilities and railroads, as well as many regulatory bodies at both the state and federal levels. Further, the concept of depreciation varies with the application, which can include capital recovery, taxes, damage claims and insurance recoveries, condemnations, and acquisitions and sales.

This fragmentation has contributed to the difficult task of adopting a standard vocabulary and definitions. Those working in depreciation should be familiar with terms that are often used to describe depreciation systems and what these terms do or do not imply. The terminology described in this chapter relates primarily to capital recovery and valuation concepts within the regulated utility and railroad industries.

Chapter 5 introduced depreciation systems that are specified by three factors. These include the method of allocation, e.g., straight line (SL), the procedure for applying the method of allocation, average life (AL) or equal life group (ELG), and the method of adjustment, amortization (AM) or remaining life (RL). This yields four possible combinations of depreciation systems. Chapter 6 added a fourth factor that included either the broad group, BG, or the vintage group, VG, models.

We normally assume that the same depreciation system will be used for both salvage and life, although combinations that further complicate the problems of definition are possible. For example, the ELG procedure is sometimes used with the average salvage, rather than aged salvage, applied to each equal life group. The result is a combination of the ELG procedure applied to life and the AL procedure applied to salvage. The high cost of decommissioning nuclear power plants has resulted in a system that combines the straight line method of allocation for life with the sinking fund method of allocation for salvage.

The terms *whole life, vintage group, broad group, ELG,* and *remaining life* are widely used to describe depreciation systems. These terms do not explicitly define the system, although each term carries with it certain implications. Unfortunately, the implications of the terms vary from user to user, so the following definitions reflect only the most common usage.

Whole life[1] depreciation is a general term used to describe any system not using the remaining life method of adjustment. Though whole life describes the length of time from initial installation to final retirement, the average life is used to calculate the accrual rate. Whole life depreciation commonly, but not necessarily, implies use of the amortization method of adjustment. As previously discussed, the amortization method of adjustment requires calculation of the variation between the calculated accumulated depreciation and accumulated provision for depreciation. *Reserve requirement* and *theoretical reserve* are synonymous with the term *calculated accumulated depreciation.* In this context, the term *ratio* refers to the calculated accumulated depreciation divided by the plant in service. This results in the terms *reserve ratio, theoretical reserve ratio,* and *calculated accumulated depreciation ratio.*

Both the American Gas Association and the Edison Electric Institute have standing committees on depreciation that have been an important industry forum for the discussion of depreciation. In 1972, the committees published a training manual titled *An Introduction to Depreciation.* A feature of the manual was the use of a pedagogical tool called the depreciation cube to help define depreciation systems. Three of the contiguous faces of the cube were labeled *methods, procedures,* and *techniques.* Each face was divided into four layers, so that the cube was divided into 64 smaller cubes. Each of the smaller cubes was characterized by one of the four methods, procedures, and techniques.

The label "methods" had the same meaning as methods of allocation as defined in Chapter 5. The label "procedures" was divided into four layers including (1) individual unit procedures; (2) equal life group procedures; (3) vintage group procedures; and (4) broad group procedures. This use of the term procedures is different from the term procedure for applying the method of allocation as defined in Chapter 5. The label "techniques" included either (1) the whole life technique or (2) the remaining life technique. Technique has a meaning that is partially similar to the term adjustment method as defined in Chapter 5. The manual describes the whole life

technique as an approach that, when the forecast of life and/or salvage is revised, changes the accrual rate to reflect the new forecasts but does *not* adjust for the fact the past accruals were calculated using the previous forecasts. Thus, the whole life technique does not require the use of the calculated accumulated depreciation. The remaining life technique and remaining life method of adjustment have the same meaning. The technique face of the depreciation cube divides both techniques into whole life and location life, so that there are four layers. However, the definition of service life as either whole life or location life is independent of the depreciation system.

The terms *broad group depreciation* and *vintage group depreciation* both imply use of the average life procedure. Both terms often, but not always, define a system that includes the amortization method of adjustment. Broad group depreciation usually refers to the SL-AL-AM system and use of the broad group model. A single average life and average net salvage ratio are chosen to represent all vintage groups in the continuous property group.

When calculating the calculated accumulated depreciation for broad groups, the difference between the average and future salvage is often ignored or assumed to equal zero. The last term of the equation $CADR(i) = (1 - ASR)[1 - RL(i)/ASL] + [ASR - FSR(i)]$ is then zero and the equation becomes $CADR(i) = (1 - ASR)[1 - RL(i)/AL]$. When the difference between the average and future salvage is significant, and the equation $CADR(i) = (1 - ASR)[1 - RL(i)/ASL] + [ASR - FSR(i)]$ is used, a single future salvage ratio is usually chosen to represent all vintages (i.e., rather than estimating a salvage schedule for the broad group and using it at age i to calculate FSR(i), a single FSR is used for all ages).

Vintage group depreciation usually refers to the SL-AL-AM system and use of the vintage group model. The term *generational arrangement* is also used, primarily by the Bell Companies, to describe the vintage group model. Aged data are required. The survivor curve for each vintage is found by using observed retirement ratios from age zero to the age at study date, then using retirement ratios from the forecast curve to complete the survivor curve. Typically, a single forecast curve (often called the future curve) is used to extend all vintages, although a different curve could be used for each vintage. If a salvage schedule has been forecast, the future salvage ratio as a function of age is calculated and used in the calculation of the CAD. It is common, however, to apply a single future salvage ratio to each vintage.

The term *ELG depreciation* typically refers to the SL-ELG-AM system. Usually a single future curve is used for all vintages (i.e., the broad group model is used), though a different future curve could be used for each vintage. Emphasis is placed on forecasting the "future curve" (i.e., the survivor curve used to describe the life characteristics of the property from the study date forward), because, under the ELG procedure, property should be fully depreciated at retirement and the accrual rate depends only on the shape of the survivor curve from the age at the study date to maximum life. It is not unusual to estimate a single average net salvage ratio and apply it to each ELG, rather than to use aged salvage with a different salvage ratio for each ELG. The use of an average salvage ratio is often the result of the lack of aged salvage data and the lack of models to estimate future salvage ratios by age.

Remaining life depreciation usually refers to the SL-AL-RL system of depreciation; use of the AL procedure is implied as is use of the same survivor curve for all vintages. Emphasis is placed on forecasting the remaining life or future curve. When calculating the future accruals, the same future salvage ratio is often used for all vintages.

Users of remaining life depreciation often do not explicitly calculate the CAD. As previously discussed, calculation of the CAD is implicit in the use of the remaining life method of adjustment, because the variation between the CAD and the accumulated provision for depreciation is automatically amortized over the remaining life. Explicit calculation of the CAD will allow the depreciation professional to find the portion of the annual accrual associated with amortization of the variation (either positive or negative).

When the ELG procedure is used with the remaining life method of adjustment, a term such as *ELG – remaining life depreciation* may be used to describe the SL-ELG-RL system. A single future survivor curve and future salvage ratio usually are applied to all vintages, although the future curve could be varied. Several pages in Chapter 6 were devoted to a discussion of the allocation of the accumulated provision for depreciation to each vintage when using this depreciation system. It was shown that allocation in proportion to the calculated future accruals resulted in a composite remaining life that is independent of the variation between the CAD and the accumulated provision for depreciation. Then the composite ELG accrual rate is calculated based on that composite remaining life.

Specify each of the four factors of a depreciation system to ensure communication. It is not safe to assume that life and salvage are treated in the same manner. Take care to indicate differences in the manner in which they are treated.

NOTE

1. *Whole life* is also used in a second context in which it is used in contrast to *location life*. When property is reused, the location life is the length of time from installation at a particular location to retirement from that location. The whole life can then be divided into a series of location lives.

8 Actuarial Methods of Developing Life Tables

FOUR basic methods of developing a life table can be used when aged data are available. These include the placement band method,[1] the experience band method, the multiple original group method, and the individual unit method. Each provides special insight to the life characteristics of the property and each has its limitations.

DATA REQUIREMENTS

The term *aged data* is used to describe the information reflecting the initial age distributions, annual additions, and the changes to that property for each year in the history of the account. Original data include the annual additions, retirements, transfers, sales, acquisitions, and other transactions. These data must be checked to ensure they are consistent, accurate, and coded so that they can be used to find the exposures and retirements for each age interval.

The aged data base used in this chapter is an account labeled Account 897–Utility Devices and is shown in Tables 8.1 and 8.2 (see end of chapter). These data contain the initial age distribution and have been simplified by assuming that the only two transactions can occur—the addition of new property and the retirement of installed property. Table 8.1 displays the

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CHAPTER XIII

THEORETICAL RESERVE STUDIES

Introduction

As discussed in Chapter IV, the sole purpose of depreciation accounting is to rateably allocate the capital costs of the property over its average service life through current charges to utility expenses. In depreciation accounting, depreciation expense is calculated either monthly or annually, charged (debited) to the current expense, and credited to the depreciation reserve (accumulated provision for depreciation account). Most commissions require that the depreciation reserve be charged (debited) at retirement with the book cost of plant and credited with any actual net salvage received. Some commissions, however, require that salvage and cost of removal be recovered through current income and expense accounts, respectively, allowing only the book (original or gross) cost of the plant to be accounted for through depreciation charges.

It is intended that the depreciation reserve at the end of an accounting period be that part of the book cost of the plant in service which has been charged to depreciation expense. If depreciation rates have been accurately estimated, the depreciation reserve will reflect the investment in service capacity, utility, or service life of the surviving plant which has been used up in operations. Therefore, the unconsumed usefulness of the plant is its book cost less the depreciation reserve.

In many regulatory customer rate-setting procedures, the depreciation reserve is a deduction from rate base. Therefore, it is desirable that the depreciation reserve be as accurate as possible. Financial reporting standards also demand accuracy.

The depreciation reserve is a balance sheet account, shown as a reduction to the property, plant, and equipment balance and is not a cash reserve. Depreciation accounting is not intended for the purpose of funding plant replacement. The cash flows resulting from the recovery of the capital invested in plant are not required to be retained in the utility accounts or assets. Utility directors have the responsibility and freedom to use these funds in accordance with their best judgement.

Theoretical Reserve In General

It is important that utility management and regulators monitor the consumed service capacity of plant and its complement—unconsumed service value. Because the dollars representing the unconsumed service value, calculated by subtracting the theoretical reserve from the book cost, must be recovered from operations over the property's average remaining life, the utility and the regulators should strive to ensure that the unrecovered dollars are reasonable in relationship to the property's remaining life.

One way to estimate this theoretical consumed service capacity of plant or the adequacy of the depreciation reserve is to perform theoretical reserve studies, often called reserve requirement studies. The results of analyses from theoretical reserve studies answer many questions about the consumption pattern of plant. However, theoretical reserve studies should not be used to modify the life and net salvage parameters for calculating future depreciation rates. If a theoretical reserve study reflects an inadequate reserve, and the service lives are reduced solely on this basis, a new theoretical reserve study based on the new service lives would indicate not a "corrected" reserve but instead a greater deficiency, calling for even higher depreciation rates. This would not be a correct application of the results of a theoretical reserve study.

Theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts. Such allocation is done when either the reserve has not been accumulated in sufficient detail or cannot be determined from utility records.

In recent years, theoretical reserve studies have been used to estimate the theoretically correct book depreciation reserve based upon past and/or future service life and net salvage considerations. Changes in technology and challenges from competition place a greater emphasis on theoretical reserve studies. Periodic comparisons of the theoretical reserves to the actual book reserves and the booking, as depreciation expense, of any reserve imbalance decrease the risk that the original cost of plant will not be recovered during its service life.

The booked consumed service capacity of plant is also expressed by the reserve ratio, which is the book depreciation reserve divided by the book plant balance. A higher ratio indicates a higher consumption of service capacity or life.

For example, the reserve and the reserve ratio, for a single unit, continually increase with each accounting period until the unit is retired. The reserve ratio for a single vintage with a large number of units, however, does not steadily increase. The ratio increases, with some fluctuations caused by the retirement dispersion, until the vintage's age equals its average service life, after which the ratio decreases with the later period retirements until the vintage's units are all retired.

The reserve ratio for an account containing several vintages also does not steadily increase. It may be affected by vintages with differing survivor curve characteristics caused by improvements which lengthen the property's service life. Other factors affecting reserve ratios are inflation and the pattern of growth in vintage installations.

Treatment of Reserve Imbalances

A reserve imbalance exists when the theoretical reserve is either greater or less than the actual reserve. If changes are made to the estimated service life and net salvage, creating a reserve imbalance, a decision must be made as to whether and how to correct the reserve imbalance. Should the imbalance be amortized (debited or credited) to the current depreciation expense over a short period of time; or should a remaining life depreciation rate be used to spread the imbalance over the future remaining life of the plant; or should future depreciation rates be adjusted to reflect the current estimated service life of the plant leaving the decision to adjust the reserve for the future? Further analysis will provide additional information to assist in making these decisions.

When a depreciation reserve imbalance exists, one should investigate why past depreciation rates, average service lives, salvage, or cost of removal amounts differ from current estimates. Care should be taken to analyze these effects before correcting for the reserve imbalances. Instances will occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known. Recognizing the nature of depreciation and its requirement for future estimations, no adjustment in annual depreciation accruals to reflect a reserve requirement, based on current rates, should be made unless there is a clear indication that the theoretical reserve is materially different from the book reserve.

Whereas the judgement of materiality is subjective, if further analysis confirms a material imbalance, one should make immediate depreciation accrual adjustments. The use of an annual amortization over a short period of time or the setting of depreciation rates using the remaining life technique are two of the most common options for eliminating the imbalance. The size of the plant account, the reserve ratio, the account remaining life, the technology of the plant in the account, and the account reserve imbalance in relationship to the account annual accrual all have a bearing on the chosen course of action.

Calculating a Theoretical Depreciation Reserve

There are two accepted methods for calculating a theoretical depreciation reserve, the prospective method and the retrospective method.

For any given class of depreciable plant, the theoretical reserve plus the estimated future depreciation accruals equals the service value of the plant (i.e., book cost less estimated net salvage). Under the prospective method, the future depreciation accruals are first estimated. Under the retrospective method, the aggregate of past net accruals (annual depreciation accruals less salvage and cost of removal) is determined.

Future depreciation accruals represent the estimated aggregate of annual depreciation charges during the average remaining life of the plant. Future depreciation accruals are based on the best available data as to past and future conditions affecting the average service lives and net salvage percentages of plant. Past accruals are calculated based upon depreciation rates deemed reasonable for the future but applied to the annual average historical plant balances.

Reasonable estimates of plant service lives, net salvage percentages, and resulting depreciation rates incorporating future conditions are used to estimate the theoretical depreciation reserve.

Prospective Method

As previously expressed, the theoretical reserve, as of the study date, is equal to the plant balance minus future accruals (the depreciation rate times the average annual plant balance times the expected remaining life in years) and minus estimated net salvage value expected at the end of the plant's average life. Expressed as a percent of book cost of plant, the theoretical reserve ratio using the prospective method is:

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PORTLAND, OREGON

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2017

Prepared by:

Gannett Fleming

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SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE
AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2017

ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)	COMPOSITE REMAINING LIFE (10)
STEAM PRODUCTION PLANT									
CHOLLA GENERATING STATION									
CHOLLA UNIT 4									
310.20 LAND RIGHTS	04-2025	SQUARE	0	1,368,465.38	447,596	920,869	125,630	9.18	7.3
311.00 STRUCTURES AND IMPROVEMENTS	04-2025	110-S0.5	(4)	65,298,661.22	27,950,844	39,959,764	5,497,254	8.42	7.3
312.00 BOILER PLANT EQUIPMENT	04-2025	65-L0.5	(5)	339,829,242.37	137,359,528	219,461,176	30,900,656	9.09	7.1
314.00 TURBOGENERATOR UNITS	04-2025	50-S0	(5)	67,630,168.43	29,390,196	41,621,481	5,963,588	8.82	7.0
315.00 ACCESSORY ELECTRIC EQUIPMENT	04-2025	80-R2.5	(4)	68,681,644.16	30,949,254	40,479,656	5,584,193	8.13	7.2
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	04-2025	45-L0	(4)	4,094,397.99	1,822,867	2,435,307	357,902	8.74	6.8
TOTAL CHOLLA UNIT 4				546,902,579.55	227,920,285	344,878,253	48,429,223	8.86	
COLSTRIP GENERATING STATION									
COLSTRIP GENERATING STATION									
311.00 STRUCTURES AND IMPROVEMENTS	12-2027	110-S0.5	(7)	62,889,070.34	35,663,657	31,627,648	3,210,655	5.11	9.9
312.00 BOILER PLANT EQUIPMENT	12-2027	65-L0.5	(7)	122,349,717.76	65,777,381	65,136,817	6,893,611	5.63	9.4
314.00 TURBOGENERATOR UNITS	12-2027	50-S0	(7)	39,185,418.35	17,903,411	24,024,987	2,540,270	6.48	9.5
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2027	80-R2.5	(6)	9,368,408.86	5,425,245	4,505,268	458,745	4.90	9.8
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2027	45-L0	(6)	443,050.73	170,329	299,305	32,219	7.27	9.3
TOTAL COLSTRIP GENERATING STATION				234,235,666.04	124,940,023	125,594,025	13,135,500	5.61	
CRAIG GENERATING STATION									
CRAIG UNIT 1									
311.00 STRUCTURES AND IMPROVEMENTS	12-2025	110-S0.5	(2)	11,663,418.07	8,000,488	3,896,198	494,863	4.24	7.9
312.00 BOILER PLANT EQUIPMENT	12-2025	65-L0.5	(3)	32,694,810.28	19,790,737	13,884,918	1,812,310	5.54	7.7
314.00 TURBOGENERATOR UNITS	12-2025	50-S0	(2)	12,879,366.22	6,168,318	6,968,636	904,859	7.03	7.7
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2025	80-R2.5	(2)	7,023,805.41	4,800,128	2,364,154	300,963	4.28	7.9
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2025	45-L0	(2)	252,778.01	163,575	94,259	12,947	5.12	7.3
TOTAL CRAIG UNIT 1				64,514,177.99	38,923,246	27,208,165	3,525,942	5.47	
CRAIG UNIT 2									
311.00 STRUCTURES AND IMPROVEMENTS	12-2026	110-S0.5	(2)	11,688,308.90	7,922,552	3,999,523	452,876	3.87	8.8
312.00 BOILER PLANT EQUIPMENT	12-2026	65-L0.5	(2)	73,776,159.82	22,334,742	52,916,941	6,021,133	8.16	8.8
314.00 TURBOGENERATOR UNITS	12-2026	50-S0	(2)	13,081,042.08	5,413,366	7,929,297	916,063	7.00	8.7
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2026	80-R2.5	(2)	7,362,179.54	4,714,443	2,794,980	316,578	4.30	8.8
TOTAL CRAIG UNIT 2				105,907,690.34	40,385,103	67,640,741	7,706,650	7.28	
CRAIG COMMON									
311.00 STRUCTURES AND IMPROVEMENTS	12-2026	110-S0.5	(2)	14,986,738.72	8,565,382	6,721,091	755,647	5.04	8.9
312.00 BOILER PLANT EQUIPMENT	12-2026	65-L0.5	(3)	28,356,297.22	16,125,649	13,081,337	1,521,039	5.36	8.6
314.00 TURBOGENERATOR UNITS	12-2026	50-S0	(3)	3,536,802.89	2,173,226	1,469,681	176,298	4.98	8.3
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2026	80-R2.5	(2)	3,016,751.34	1,860,738	1,216,348	137,453	4.56	8.8
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2026	45-L0	(2)	987,516.59	602,393	404,874	49,837	5.05	8.1
TOTAL CRAIG COMMON				50,884,106.76	29,327,388	22,893,331	2,640,274	5.19	
TOTAL CRAIG GENERATING STATION				221,305,975.09	108,635,737	117,742,237	13,872,866	6.27	

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SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2017

ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)	COMPOSITE REMAINING LIFE (10)
DAVE JOHNSTON GENERATING STATION									
DAVE JOHNSTON UNIT 1									
311.00 STRUCTURES AND IMPROVEMENTS	12-2027	110-S0.5	(3)	1,009,703.51	408,121	631,874	63,608	6.30	9.9
312.00 BOILER PLANT EQUIPMENT	12-2027	65-L0.5	(4)	53,900,429.82	27,809,720	28,246,727	2,952,549	5.48	9.6
314.00 TURBOGENERATOR UNITS	12-2027	50-S0	(4)	11,519,074.01	6,083,138	5,896,699	631,808	5.48	9.3
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2027	80-R2.5	(4)	2,832,890.24	1,895,910	1,050,296	108,544	3.83	9.7
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2027	45-L0	(3)	2,674.50	1,502	1,253	138	5.16	9.1
TOTAL DAVE JOHNSTON UNIT 1				69,264,772.08	36,198,391	35,826,849	3,756,647	5.42	
DAVE JOHNSTON UNIT 2									
311.00 STRUCTURES AND IMPROVEMENTS	12-2027	110-S0.5	(3)	566,770.57	246,041	337,733	34,023	6.00	9.9
312.00 BOILER PLANT EQUIPMENT	12-2027	65-L0.5	(4)	57,165,778.38	28,662,033	30,790,377	3,212,938	5.62	9.6
314.00 TURBOGENERATOR UNITS	12-2027	50-S0	(4)	15,679,466.75	8,431,433	7,875,212	842,351	5.37	9.3
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2027	80-R2.5	(4)	3,491,873.59	2,018,971	1,612,578	164,615	4.71	9.8
TOTAL DAVE JOHNSTON UNIT 2				76,903,889.29	39,358,478	40,615,900	4,253,927	5.53	
DAVE JOHNSTON UNIT 3									
311.00 STRUCTURES AND IMPROVEMENTS	12-2027	110-S0.5	(3)	18,967,793.01	8,253,453	11,283,374	1,135,550	5.99	9.9
312.00 BOILER PLANT EQUIPMENT	12-2027	65-L0.5	(4)	225,762,795.52	91,523,481	143,269,826	14,782,447	6.55	9.7
314.00 TURBOGENERATOR UNITS	12-2027	50-S0	(4)	21,486,724.45	12,035,357	10,310,836	1,105,959	5.15	9.3
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2027	80-R2.5	(3)	14,788,456.81	6,547,573	8,684,538	876,504	5.93	9.9
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2027	45-L0	(3)	240,204.09	130,663	116,747	12,773	5.32	9.1
TOTAL DAVE JOHNSTON UNIT 3				281,245,973.88	118,490,527	173,665,321	17,913,233	6.37	
DAVE JOHNSTON UNIT 4									
311.00 STRUCTURES AND IMPROVEMENTS	12-2027	110-S0.5	(3)	15,159,815.23	5,592,884	10,021,726	1,008,184	6.65	9.9
312.00 BOILER PLANT EQUIPMENT	12-2027	65-L0.5	(4)	230,895,488.29	89,774,414	150,356,893	15,502,957	6.71	9.7
314.00 TURBOGENERATOR UNITS	12-2027	50-S0	(4)	41,342,089.77	20,015,651	22,980,122	2,423,557	5.86	9.5
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2027	80-R2.5	(3)	14,405,447.38	6,229,315	8,608,296	868,908	6.03	9.9
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2027	45-L0	(3)	599,327.00	308,418	308,889	33,623	5.61	9.2
TOTAL DAVE JOHNSTON UNIT 4				302,402,167.67	121,920,682	192,275,926	19,837,229	6.56	
DAVE JOHNSTON COMMON									
310.20 LAND RIGHTS	12-2027	SQUARE	0	99,970.26	68,953	31,017	3,102	3.10	10.0
311.00 STRUCTURES AND IMPROVEMENTS	12-2027	110-S0.5	(3)	124,033,278.41	58,661,749	69,092,528	6,965,974	5.62	9.9
312.00 BOILER PLANT EQUIPMENT	12-2027	65-L0.5	(4)	128,855,245.66	56,555,784	77,453,671	8,014,214	6.22	9.7
314.00 TURBOGENERATOR UNITS	12-2027	50-S0	(4)	9,678,356.75	3,878,753	6,186,738	643,265	6.65	9.6
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2027	80-R2.5	(3)	27,630,145.51	10,225,915	18,233,135	1,834,444	6.64	9.9
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2027	45-L0	(3)	7,701,233.17	3,298,954	4,633,316	498,552	6.47	9.3
TOTAL DAVE JOHNSTON COMMON				297,998,229.76	132,690,108	175,630,405	17,959,551	6.03	
TOTAL DAVE JOHNSTON GENERATING STATION				1,027,815,032.68	448,658,186	618,014,401	63,720,587	6.20	

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AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2017

	ACCOUNT	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	GADSBY GENERATING STATION									
	GADSBY UNIT 1									
311.00	STRUCTURES AND IMPROVEMENTS	12-2032	110-S0.5	(15)	1,231,253.41	1,355,810	60,131	4,050	0.33	14.8
312.00	BOILER PLANT EQUIPMENT	12-2032	65-L0.5	(15)	10,281,867.93	9,439,032	2,385,116	171,199	1.67	13.9
314.00	TURBOGENERATOR UNITS	12-2032	50-S0	(14)	5,485,093.65	5,531,754	721,253	53,203	0.97	13.6
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2032	80-R2.5	(15)	1,394,621.84	1,456,947	146,868	9,961	0.71	14.7
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2032	45-L0	(10)	21,261.95	22,223	1,165	104	0.49	11.2
	TOTAL GADSBY UNIT 1				18,414,098.78	17,805,766	3,314,533	238,517	1.30	
	GADSBY UNIT 2									
311.00	STRUCTURES AND IMPROVEMENTS	12-2032	110-S0.5	(16)	1,105,143.55	1,267,910	14,057	942	0.09	14.9
312.00	BOILER PLANT EQUIPMENT	12-2032	65-L0.5	(15)	13,771,032.70	13,018,025	2,818,663	203,224	1.48	13.9
314.00	TURBOGENERATOR UNITS	12-2032	50-S0	(14)	6,369,161.73	5,888,746	1,372,098	97,543	1.53	14.1
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2032	80-R2.5	(15)	1,406,724.29	1,506,902	110,831	7,498	0.53	14.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2032	45-L0	(10)	12,702.95	13,242	731	65	0.51	11.2
	TOTAL GADSBY UNIT 2				22,664,765.22	21,694,825	4,316,380	309,272	1.36	
	GADSBY UNIT 3									
311.00	STRUCTURES AND IMPROVEMENTS	12-2032	110-S0.5	(15)	1,204,199.60	1,277,360	107,470	7,232	0.60	14.9
312.00	BOILER PLANT EQUIPMENT	12-2032	65-L0.5	(15)	13,813,700.85	12,829,943	3,055,813	218,518	1.58	14.0
314.00	TURBOGENERATOR UNITS	12-2032	50-S0	(14)	7,607,743.65	6,606,906	2,065,922	146,567	1.93	14.1
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2032	80-R2.5	(14)	2,512,536.04	2,135,531	728,760	49,198	1.96	14.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2032	45-L0	(10)	46,931.11	48,557	3,067	269	0.57	11.4
	TOTAL GADSBY UNIT 3				25,185,111.25	22,898,297	5,961,032	421,784	1.67	
	GADSBY COMMON									
311.00	STRUCTURES AND IMPROVEMENTS	12-2032	110-S0.5	(15)	11,719,240.32	11,085,607	2,391,519	162,457	1.39	14.7
312.00	BOILER PLANT EQUIPMENT	12-2032	65-L0.5	(15)	1,410,971.82	1,002,550	620,068	43,750	3.10	14.2
314.00	TURBOGENERATOR UNITS	12-2032	50-S0	(14)	475,708.66	380,772	161,536	11,823	2.49	13.7
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2032	80-R2.5	(14)	3,108,417.44	1,898,504	1,645,092	110,917	3.57	14.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2032	45-L0	(12)	377,082.73	295,143	127,190	9,771	2.59	13.0
	TOTAL GADSBY COMMON				17,091,420.97	14,662,576	4,945,405	338,718	1.98	
	TOTAL GADSBY GENERATING STATION				83,355,396.22	77,061,464	18,537,350	1,308,291	1.57	
	HAYDEN GENERATING STATION									
	HAYDEN UNIT 1									
311.00	STRUCTURES AND IMPROVEMENTS	12-2030	110-S0.5	(2)	1,130,877.82	866,288	287,207	22,799	2.02	12.6
312.00	BOILER PLANT EQUIPMENT	12-2030	65-L0.5	(2)	46,888,076.85	19,537,467	28,288,372	2,272,412	4.85	12.4
314.00	TURBOGENERATOR UNITS	12-2030	50-S0	(3)	5,115,407.60	2,818,785	2,450,085	204,569	4.00	12.0
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2030	80-R2.5	(2)	1,025,966.48	750,660	295,826	23,655	2.31	12.5
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2030	45-L0	(1)	250,077.04	155,343	97,235	8,544	3.42	11.4
	TOTAL HAYDEN UNIT 1				54,410,405.79	24,128,543	31,418,725	2,531,979	4.65	
	HAYDEN UNIT 2									
311.00	STRUCTURES AND IMPROVEMENTS	12-2030	110-S0.5	(2)	1,824,739.87	1,372,818	488,417	38,652	2.12	12.6
312.00	BOILER PLANT EQUIPMENT	12-2030	65-L0.5	(2)	23,870,337.52	9,618,260	14,729,484	1,181,914	4.95	12.5
314.00	TURBOGENERATOR UNITS	12-2030	50-S0	(3)	4,502,907.72	2,251,397	2,386,598	196,550	4.36	12.1
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2030	80-R2.5	(2)	1,331,900.75	1,005,486	353,053	28,175	2.12	12.5
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2030	45-L0	(2)	225,059.01	160,323	69,237	6,321	2.81	11.0
	TOTAL HAYDEN UNIT 2				31,754,944.87	14,408,284	18,026,789	1,451,612	4.57	

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ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)	COMPOSITE REMAINING LIFE (10)
HAYDEN COMMON									
311.00 STRUCTURES AND IMPROVEMENTS	12-2030	110-S0.5	(1)	14,895,847.59	5,907,166	9,137,640	708,801	4.76	12.9
312.00 BOILER PLANT EQUIPMENT	12-2030	65-L0.5	(3)	12,552,644.25	7,463,565	5,465,659	448,006	3.57	12.2
314.00 TURBOGENERATOR UNITS	12-2030	50-S0	(2)	251,779.69	111,988	144,827	11,801	4.69	12.3
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2030	80-R2.5	(2)	206,074.98	157,344	52,852	4,240	2.06	12.5
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2030	45-L0	(2)	164,676.61	117,102	50,868	4,654	2.83	10.9
TOTAL HAYDEN COMMON				28,071,023.12	13,757,165	14,851,846	1,177,502	4.19	
TOTAL HAYDEN GENERATING STATION				114,236,373.78	52,293,992	64,297,360	5,161,093	4.52	
HUNTER GENERATING STATION									
HUNTER UNIT 1									
311.00 STRUCTURES AND IMPROVEMENTS	12-2042	110-S0.5	(8)	23,087,746.97	12,981,825	11,952,942	506,520	2.19	23.6
312.00 BOILER PLANT EQUIPMENT	12-2042	65-L0.5	(8)	261,606,237.44	70,432,245	212,102,491	9,398,768	3.59	22.6
314.00 TURBOGENERATOR UNITS	12-2042	50-S0	(8)	65,893,472.99	21,851,930	49,313,021	2,297,732	3.49	21.5
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2042	80-R2.5	(7)	34,023,338.80	15,636,661	20,768,312	879,230	2.58	23.6
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2042	45-L0	(5)	802,524.57	388,452	454,199	24,863	3.10	18.3
TOTAL HUNTER UNIT 1				385,413,320.77	121,291,113	294,590,965	13,107,113	3.40	
HUNTER UNIT 2									
311.00 STRUCTURES AND IMPROVEMENTS	12-2042	110-S0.5	(8)	12,463,799.68	6,760,445	6,700,459	282,793	2.27	23.7
312.00 BOILER PLANT EQUIPMENT	12-2042	65-L0.5	(8)	166,451,599.78	46,987,053	132,780,675	5,897,438	3.54	22.5
314.00 TURBOGENERATOR UNITS	12-2042	50-S0	(8)	45,811,481.56	14,796,967	34,679,433	1,610,613	3.52	21.5
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2042	80-R2.5	(7)	16,705,865.55	8,550,683	9,324,593	397,624	2.38	23.5
TOTAL HUNTER UNIT 2				241,432,746.57	77,095,148	183,485,160	8,188,468	3.39	
HUNTER UNIT 3									
311.00 STRUCTURES AND IMPROVEMENTS	12-2042	110-S0.5	(8)	55,726,198.77	30,094,730	30,089,565	1,268,271	2.28	23.7
312.00 BOILER PLANT EQUIPMENT	12-2042	65-L0.5	(9)	297,167,684.88	127,155,676	196,757,100	9,091,064	3.06	21.6
314.00 TURBOGENERATOR UNITS	12-2042	50-S0	(8)	84,572,092.21	22,497,723	68,840,137	3,145,802	3.72	21.9
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2042	80-R2.5	(7)	54,654,006.81	28,511,040	29,968,747	1,276,238	2.34	23.5
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2042	45-L0	(5)	1,633,585.53	733,950	981,315	52,287	3.20	18.8
TOTAL HUNTER UNIT 3				493,753,568.20	208,993,119	326,636,864	14,833,662	3.00	
HUNTER UNITS 1 AND 2 COMMON									
311.00 STRUCTURES AND IMPROVEMENTS	12-2042	110-S0.5	(8)	9,407,855.06	5,213,693	4,946,790	209,289	2.22	23.6
312.00 BOILER PLANT EQUIPMENT	12-2042	65-L0.5	(9)	11,880,289.11	4,218,597	8,730,918	394,676	3.32	22.1
314.00 TURBOGENERATOR UNITS	12-2042	50-S0	(8)	3,862,957.70	1,524,615	2,647,379	126,392	3.27	20.9
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2042	80-R2.5	(6)	101,813.37	29,882	78,040	3,231	3.17	24.2
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2042	45-L0	(5)	823,901.93	406,448	458,649	25,181	3.06	18.2
TOTAL HUNTER UNITS 1 AND 2 COMMON				26,076,817.17	11,393,235	16,861,776	758,769	2.91	
HUNTER UNITS 1, 2 AND 3 COMMON									
310.20 LAND RIGHTS	12-2042	SQUARE	0	246,337.54	128,259	118,079	4,723	1.92	25.0
311.00 STRUCTURES AND IMPROVEMENTS	12-2042	110-S0.5	(8)	110,862,576.37	56,801,192	62,930,390	2,642,641	2.38	23.8
312.00 BOILER PLANT EQUIPMENT	12-2042	65-L0.5	(9)	27,893,990.15	9,772,619	20,631,830	931,694	3.34	22.1
314.00 TURBOGENERATOR UNITS	12-2042	50-S0	(8)	1,216,238.53	441,905	871,633	41,306	3.40	21.1
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2042	80-R2.5	(6)	1,620,033.99	455,229	1,262,007	51,712	3.19	24.4
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2042	45-L0	(5)	467,453.79	133,335	357,491	17,630	3.77	20.3
TOTAL HUNTER UNITS 1, 2 AND 3 COMMON				142,306,630.37	67,732,539	86,171,430	3,689,706	2.59	
TOTAL HUNTER GENERATING STATION				1,288,983,083.08	486,505,154	907,746,195	40,577,718	3.15	

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ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)	COMPOSITE REMAINING LIFE (10)
HUNTINGTON GENERATING STATION									
HUNTINGTON UNIT 1									
311.00 STRUCTURES AND IMPROVEMENTS	12-2036	110-S0.5	(8)	19,875,771.48	12,531,027	8,934,806	490,250	2.47	18.2
312.00 BOILER PLANT EQUIPMENT	12-2036	65-L0.5	(8)	285,637,455.74	96,419,055	212,069,397	12,007,216	4.20	17.7
314.00 TURBOGENERATOR UNITS	12-2036	50-S0	(8)	60,599,828.45	22,776,978	42,670,837	2,494,328	4.12	17.1
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2036	80-R2.5	(7)	20,033,655.55	11,480,234	9,955,777	548,171	2.74	18.2
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2036	45-L0	(5)	1,231,362.67	460,951	831,980	51,678	4.20	16.1
TOTAL HUNTINGTON UNIT 1				387,378,073.89	143,668,245	274,462,797	15,591,643	4.02	
HUNTINGTON UNIT 2									
311.00 STRUCTURES AND IMPROVEMENTS	12-2036	110-S0.5	(7)	26,221,908.41	13,773,947	14,283,495	774,337	2.95	18.4
312.00 BOILER PLANT EQUIPMENT	12-2036	65-L0.5	(8)	244,166,820.97	92,981,527	170,718,640	9,735,767	3.99	17.5
314.00 TURBOGENERATOR UNITS	12-2036	50-S0	(8)	58,102,496.24	24,945,174	37,805,522	2,246,438	3.87	16.8
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2036	80-R2.5	(7)	23,780,251.95	11,124,013	14,320,857	775,794	3.26	18.5
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2036	45-L0	(5)	971,260.90	421,962	597,862	37,836	3.90	15.8
TOTAL HUNTINGTON UNIT 2				353,242,738.47	143,246,623	237,726,376	13,570,172	3.84	
HUNTINGTON COMMON									
311.00 STRUCTURES AND IMPROVEMENTS	12-2036	110-S0.5	(7)	78,868,409.31	41,765,580	42,623,618	2,312,928	2.93	18.4
312.00 BOILER PLANT EQUIPMENT	12-2036	65-L0.5	(8)	35,691,626.66	11,973,860	26,573,097	1,504,960	4.22	17.7
314.00 TURBOGENERATOR UNITS	12-2036	50-S0	(8)	6,868,882.79	3,648,462	3,769,931	233,599	3.40	16.1
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2036	80-R2.5	(6)	3,841,106.38	1,143,989	2,927,584	156,434	4.07	18.7
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2036	45-L0	(5)	687,005.62	207,822	513,534	31,228	4.55	16.4
TOTAL HUNTINGTON COMMON				125,957,030.76	58,739,713	76,407,764	4,239,149	3.37	
TOTAL HUNTINGTON GENERATING STATION				866,577,843.12	345,654,581	588,596,937	33,400,964	3.85	
JIM BRIDGER GENERATING STATION									
JIM BRIDGER UNIT 1									
311.00 STRUCTURES AND IMPROVEMENTS	12-2028	110-S0.5	(6)	15,444,457.12	10,890,798	5,480,327	509,582	3.30	10.8
312.00 BOILER PLANT EQUIPMENT	12-2028	65-L0.5	(6)	163,868,313.29	88,072,690	85,627,722	8,173,135	4.99	10.5
314.00 TURBOGENERATOR UNITS	12-2028	50-S0	(6)	46,262,991.29	21,885,659	27,153,112	2,605,634	5.63	10.4
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2028	80-R2.5	(5)	10,831,455.56	7,488,813	3,884,215	363,500	3.36	10.7
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2028	45-L0	(5)	313,727.10	214,710	114,703	12,065	3.85	9.5
TOTAL JIM BRIDGER UNIT 1				236,720,944.36	128,552,670	122,260,079	11,663,916	4.93	
JIM BRIDGER UNIT 2									
311.00 STRUCTURES AND IMPROVEMENTS	12-2032	110-S0.5	(6)	12,835,787.27	8,535,173	5,070,762	349,548	2.72	14.5
312.00 BOILER PLANT EQUIPMENT	12-2032	65-L0.5	(7)	172,760,855.57	77,248,718	107,605,397	7,657,966	4.43	14.1
314.00 TURBOGENERATOR UNITS	12-2032	50-S0	(6)	59,810,740.93	20,423,812	42,975,573	3,061,698	5.12	14.0
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2032	80-R2.5	(6)	9,183,856.22	5,887,360	3,847,528	267,093	2.91	14.4
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2032	45-L0	(5)	198,482.09	122,489	85,917	6,963	3.51	12.3
TOTAL JIM BRIDGER UNIT 2				254,789,722.08	112,217,552	159,585,177	11,343,268	4.45	
JIM BRIDGER UNIT 3									
311.00 STRUCTURES AND IMPROVEMENTS	12-2037	110-S0.5	(7)	12,952,713.64	7,931,502	5,927,902	310,309	2.40	19.1
312.00 BOILER PLANT EQUIPMENT	12-2037	65-L0.5	(7)	259,370,184.73	73,591,270	203,934,828	10,975,888	4.23	18.6
314.00 TURBOGENERATOR UNITS	12-2037	50-S0	(7)	44,135,026.54	16,352,072	30,872,406	1,736,998	3.94	17.8
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2037	80-R2.5	(6)	7,764,833.16	4,437,815	3,792,908	200,205	2.58	18.9
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2037	45-L0	(5)	192,485.09	106,547	95,562	6,196	3.22	15.4
TOTAL JIM BRIDGER UNIT 3				324,415,243.16	102,419,206	244,623,606	13,229,596	4.08	

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ACCOUNT (1)		PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)	COMPOSITE REMAINING LIFE (10)
	JIM BRIDGER UNIT 4									
311.00	STRUCTURES AND IMPROVEMENTS	12-2037	110-S0.5	(7)	39,910,921.16	24,358,517	18,346,169	959,098	2.40	19.1
312.00	BOILER PLANT EQUIPMENT	12-2037	65-L0.5	(7)	292,327,991.65	82,397,100	230,393,851	12,400,744	4.24	18.6
314.00	TURBOGENERATOR UNITS	12-2037	50-S0	(7)	45,562,255.38	19,196,817	29,554,796	1,685,617	3.70	17.5
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2037	80-R2.5	(6)	16,795,185.05	9,900,015	7,902,881	417,136	2.48	18.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2037	45-L0	(5)	1,248,549.58	690,850	620,127	40,129	3.21	15.5
	TOTAL JIM BRIDGER UNIT 4				395,844,902.82	136,543,299	286,817,824	15,502,724	3.92	
	JIM BRIDGER COMMON									
310.20	LAND RIGHTS	12-2037	SQUARE	0	281,111.10	167,820	113,291	5,665	2.02	20.0
311.00	STRUCTURES AND IMPROVEMENTS	12-2037	110-S0.5	(6)	66,639,317.91	31,866,353	38,771,324	1,997,242	3.00	19.4
312.00	BOILER PLANT EQUIPMENT	12-2037	65-L0.5	(7)	88,282,141.47	36,677,837	57,784,054	3,185,985	3.61	18.1
314.00	TURBOGENERATOR UNITS	12-2037	50-S0	(7)	8,987,585.66	3,131,182	6,485,535	362,063	4.03	17.9
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2037	80-R2.5	(6)	16,589,262.63	7,421,260	10,163,358	527,109	3.18	19.3
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2037	45-L0	(5)	2,945,261.07	643,099	2,449,425	140,571	4.77	17.4
	TOTAL JIM BRIDGER COMMON				183,724,679.84	79,907,551	115,766,987	6,218,635	3.38	
TOTAL JIM BRIDGER GENERATING STATION					1,395,495,492.26	559,640,278	929,053,673	57,958,139	4.15	
NAUGHTON GENERATING STATION										
	NAUGHTON UNIT 1									
311.00	STRUCTURES AND IMPROVEMENTS	12-2029	110-S0.5	(9)	21,183,661.39	9,622,256	13,467,935	1,134,097	5.35	11.9
312.00	BOILER PLANT EQUIPMENT	12-2029	65-L0.5	(9)	153,575,974.49	49,600,365	117,797,447	10,174,654	6.63	11.6
314.00	TURBOGENERATOR UNITS	12-2029	50-S0	(9)	20,697,020.27	8,986,511	13,573,241	1,212,166	5.86	11.2
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2029	80-R2.5	(9)	20,963,379.01	7,006,100	15,843,983	1,332,665	6.36	11.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2029	45-L0	(7)	95,888.60	63,172	39,429	3,991	4.16	9.9
	TOTAL NAUGHTON UNIT 1				216,515,923.76	75,278,404	160,722,035	13,857,573	6.40	
	NAUGHTON UNIT 2									
311.00	STRUCTURES AND IMPROVEMENTS	12-2029	110-S0.5	(9)	29,362,133.06	9,988,184	22,016,541	1,848,755	6.30	11.9
312.00	BOILER PLANT EQUIPMENT	12-2029	65-L0.5	(9)	182,428,075.00	65,202,677	133,643,924	11,571,143	6.34	11.5
314.00	TURBOGENERATOR UNITS	12-2029	50-S0	(9)	24,029,373.81	9,988,104	16,203,913	1,435,422	5.97	11.3
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2029	80-R2.5	(8)	30,169,717.39	10,132,389	22,450,906	1,886,586	6.25	11.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2029	45-L0	(7)	388,871.65	247,483	168,610	16,638	4.28	10.1
	TOTAL NAUGHTON UNIT 2				266,378,170.91	95,558,837	194,483,894	16,758,544	6.29	
	NAUGHTON UNIT 3									
311.00	STRUCTURES AND IMPROVEMENTS	12-2029	110-S0.5	(8)	14,217,011.61	8,789,291	6,565,082	558,678	3.93	11.8
312.00	BOILER PLANT EQUIPMENT	12-2029	65-L0.5	(8)	146,425,465.03	72,522,508	85,616,994	7,548,017	5.15	11.3
314.00	TURBOGENERATOR UNITS	12-2029	50-S0	(8)	39,070,893.87	17,713,352	24,483,213	2,180,724	5.58	11.2
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2029	80-R2.5	(8)	11,439,683.73	6,512,982	5,841,876	498,310	4.36	11.7
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2029	45-L0	(8)	206,305.08	133,406	89,403	8,843	4.29	10.1
	TOTAL NAUGHTON UNIT 3				211,359,359.32	105,671,539	122,596,568	10,794,572	5.11	
	NAUGHTON COMMON									
310.20	LAND RIGHTS	12-2029	SQUARE	0	15,015.87	10,023	4,993	416	2.77	12.0
311.00	STRUCTURES AND IMPROVEMENTS	12-2029	110-S0.5	(9)	60,663,426.84	26,527,041	39,596,094	3,336,403	5.50	11.9
312.00	BOILER PLANT EQUIPMENT	12-2029	65-L0.5	(10)	36,243,209.67	17,793,173	22,074,358	1,941,142	5.36	11.4
314.00	TURBOGENERATOR UNITS	12-2029	50-S0	(9)	1,299,219.18	573,149	843,000	74,512	5.74	11.3
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2029	80-R2.5	(9)	3,594,795.93	1,483,341	2,434,987	205,130	5.71	11.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2029	45-L0	(8)	1,640,331.97	593,352	1,178,207	106,902	6.52	11.0
	TOTAL NAUGHTON COMMON				103,455,999.46	46,980,079	66,131,639	5,664,505	5.48	
TOTAL NAUGHTON GENERATING STATION					797,709,453.45	323,488,859	543,934,136	47,075,194	5.90	

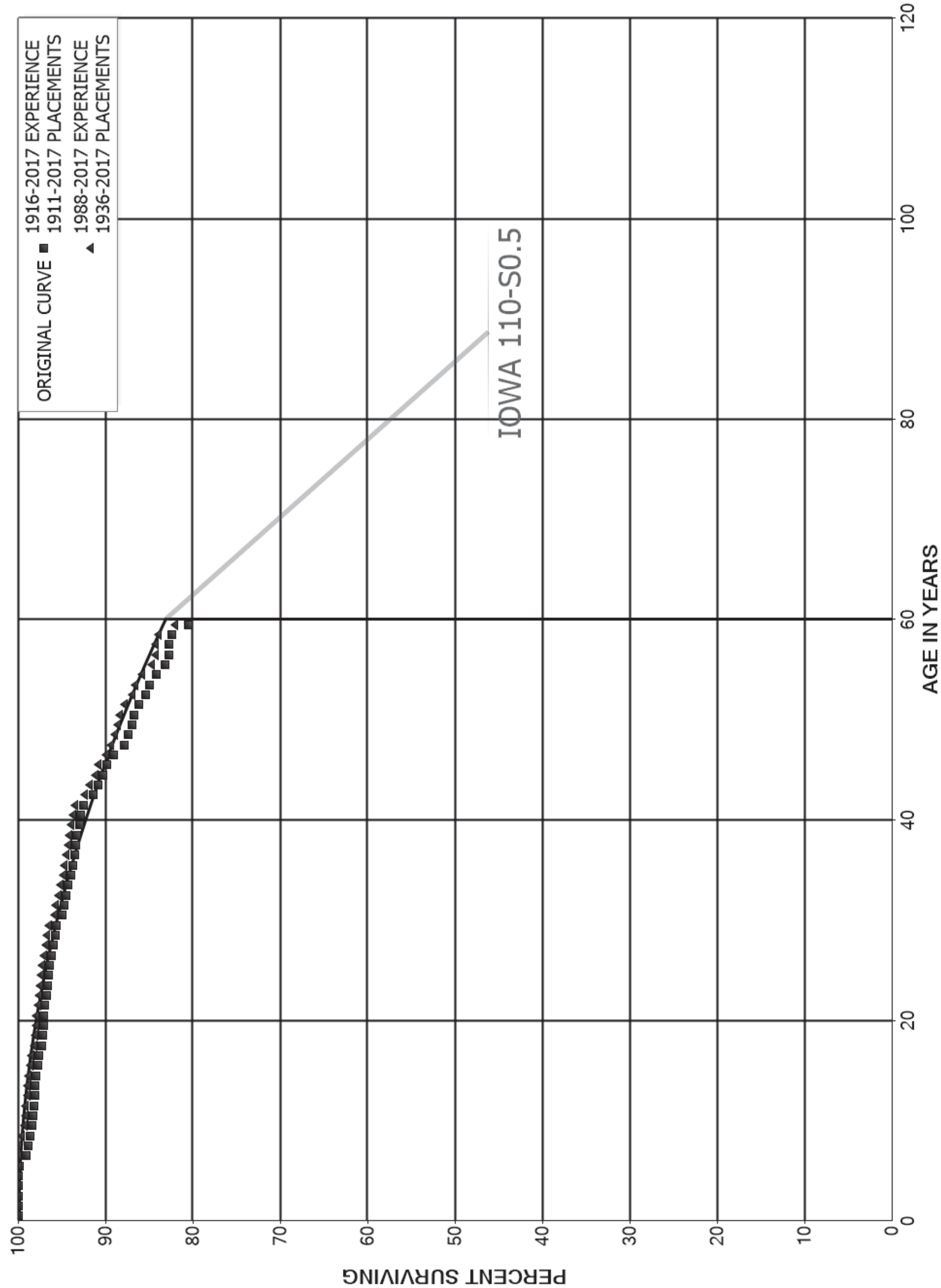
PACIFICORP

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE
AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2017

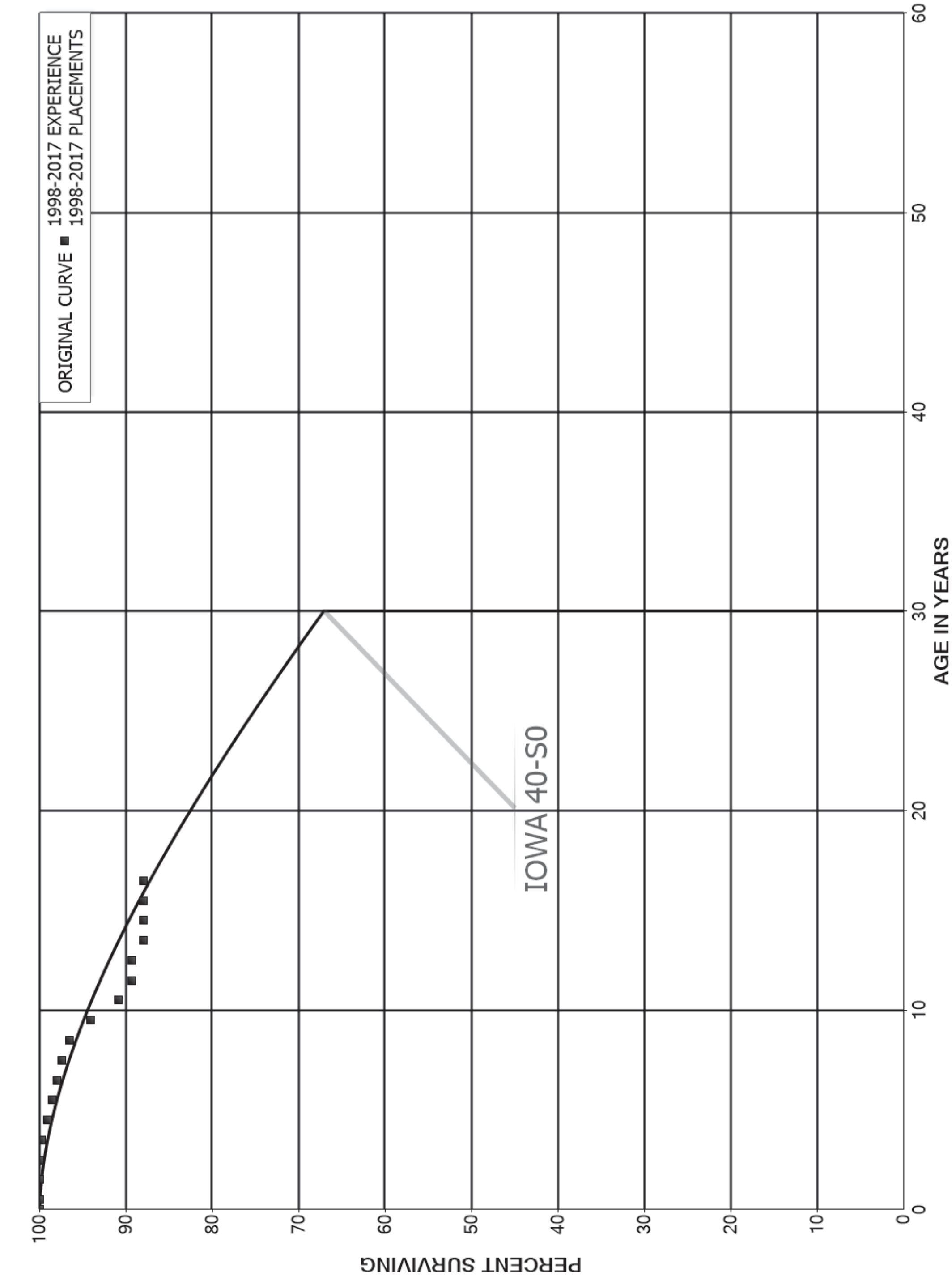
ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)	CALCULATED ANNUAL ACCRUAL RATE (9)	COMPOSITE REMAINING LIFE (10)
WYODAK GENERATING STATION									
WYODAK PLANT									
310.20 LAND RIGHTS	12-2039	SQUARE	0	164,796.80	96,508	68,289	3,104	1.88	22.0
311.00 STRUCTURES AND IMPROVEMENTS	12-2039	110-S0.5	(4)	52,514,611.28	29,656,605	24,958,591	1,183,512	2.25	21.1
312.00 BOILER PLANT EQUIPMENT	12-2039	65-L0.5	(6)	314,166,615.59	121,141,610	211,875,003	10,652,920	3.39	19.9
314.00 TURBOGENERATOR UNITS	12-2039	50-S0	(6)	66,824,527.16	26,827,120	44,006,879	2,308,588	3.45	19.1
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2039	80-R2.5	(4)	28,620,937.31	14,049,696	15,716,079	745,582	2.61	21.1
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2039	45-L0	(3)	1,285,660.94	399,586	924,645	50,246	3.91	18.4
TOTAL WYODAK GENERATING STATION				463,577,149.08	192,171,125	297,549,486	14,943,952	3.22	
BLUNDELL GENERATING STATION									
BLUNDELL GEOTHERMAL UNIT 1									
311.00 STRUCTURES AND IMPROVEMENTS	12-2037	110-S0.5	(9)	6,647,157.15	3,811,151	3,434,250	178,002	2.68	19.3
312.00 BOILER PLANT EQUIPMENT	12-2037	65-L0.5	(11)	13,209,813.07	7,142,094	7,520,799	426,051	3.23	17.7
314.00 TURBOGENERATOR UNITS	12-2037	50-S0	(10)	17,777,812.05	8,414,707	11,140,886	643,606	3.62	17.3
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2037	80-R2.5	(9)	5,045,404.31	2,858,494	2,640,997	137,643	2.73	19.2
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2037	45-L0	(7)	707,680.85	324,607	432,612	26,479	3.74	16.3
TOTAL BLUNDELL GEOTHERMAL UNIT 1				43,387,867.43	22,551,053	25,169,544	1,411,781	3.25	
BLUNDELL GEOTHERMAL UNIT 2									
311.00 STRUCTURES AND IMPROVEMENTS	12-2037	110-S0.5	(9)	689,372.12	214,164	537,252	27,296	3.96	19.7
312.00 BOILER PLANT EQUIPMENT	12-2037	65-L0.5	(10)	8,005,814.53	2,387,692	6,418,704	344,883	4.31	18.6
314.00 TURBOGENERATOR UNITS	12-2037	50-S0	(9)	16,439,393.14	5,407,208	12,511,731	688,935	4.19	18.2
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2037	80-R2.5	(8)	2,453,737.00	812,443	1,837,593	93,421	3.81	19.7
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2037	45-L0	(7)	545,275.12	173,344	410,100	24,025	4.41	17.1
TOTAL BLUNDELL GEOTHERMAL UNIT 2				28,133,591.91	8,994,851	21,715,380	1,178,560	4.19	
BLUNDELL GEOTHERMAL STEAM FIELD									
310.20 LAND RIGHTS	12-2037	SQUARE	0	40,981,910.43	27,554,811	13,427,099	671,354	1.64	20.0
311.00 STRUCTURES AND IMPROVEMENTS	12-2037	110-S0.5	(7)	250,763.16	90,498	177,819	9,022	3.60	19.7
312.00 BOILER PLANT EQUIPMENT	12-2037	65-L0.5	(8)	37,595,724.57	10,614,308	29,989,075	1,593,515	4.24	18.8
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2037	80-R2.5	(7)	1,033,795.62	192,313	913,848	46,224	4.47	19.8
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2037	45-L0	(6)	125,101.43	23,280	109,328	6,187	4.95	17.7
TOTAL BLUNDELL GEOTHERMAL STEAM FIELD				79,987,295.21	38,475,210	44,617,169	2,326,302	2.91	
BLUNDELL GEOTHERMAL COMMON									
311.00 STRUCTURES AND IMPROVEMENTS	12-2037	110-S0.5	(9)	740,245.01	207,274	599,593	30,422	4.11	19.7
312.00 BOILER PLANT EQUIPMENT	12-2037	65-L0.5	(10)	270,620.15	79,085	218,597	11,734	4.34	18.6
315.00 ACCESSORY ELECTRIC EQUIPMENT	12-2037	80-R2.5	(8)	42,332.23	8,790	36,929	1,871	4.42	19.7
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	12-2037	45-L0	(7)	74,760.16	40,955	39,038	2,483	3.32	15.7
TOTAL BLUNDELL GEOTHERMAL COMMON				1,127,957.55	336,104	894,157	46,510	4.12	
TOTAL BLUNDELL GENERATING STATION				152,636,712.10	70,357,218	92,396,250	4,963,153	3.25	
TOTAL DEPRECIABLE STEAM PRODUCTION PLANT				**7,192,830,756.45**	**3,017,326,903**	**4,648,340,303**	**344,546,680**	**4.79**	

Exhibit PAC/202
Spanos/80

PACIFICORP
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



PACIFICORP
ACCOUNT 344 GENERATORS - WIND
ORIGINAL AND SMOOTH SURVIVOR CURVES



PUGET SOUND ENERGY

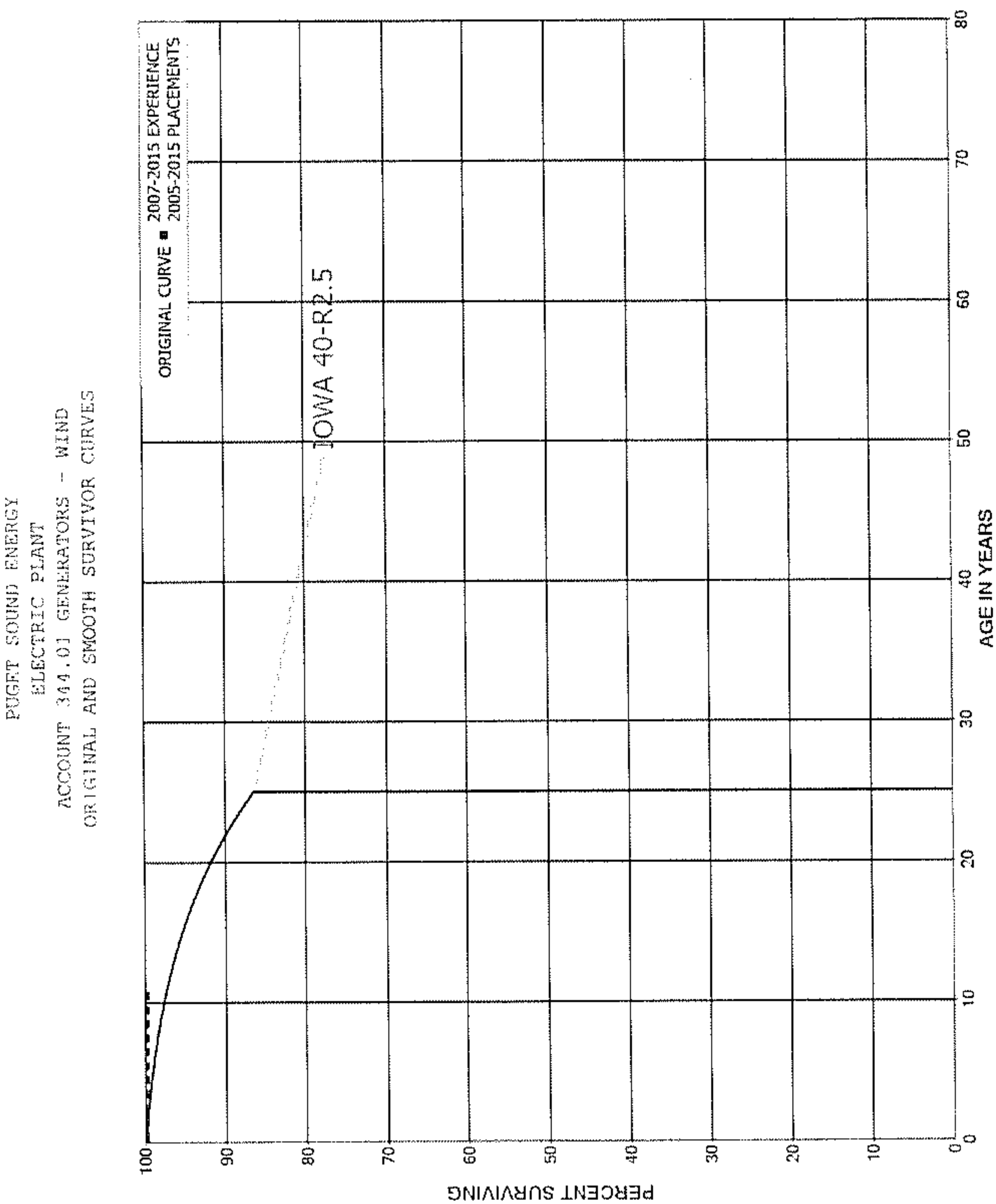
2016 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC, GAS AND COMMON PLANT AS OF SEPTEMBER 30, 2016

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***


PUGET SOUND ENERGY
ELECTRIC PLANT
ACCOUNT 344.01 GENERATORS - WIND
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE ■ 2007-2015 EXPERIENCE
2005-2015 PLACEMENTS
IOWA 40-R2.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100

Docket No. UM ____
Exhibit PAC/200
Witness: John J. Spanos

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of John J. Spanos

September 2018

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/201—Witness Qualifications

Exhibit PAC/202—Depreciation Study

Exhibit PAC/203—Oregon Steam Production Plant

Q. Please state your name and address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

Q. Are you associated with any firm?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming).

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since college graduation in June 1986.

Q. What is your position with the firm?

A. I am a Senior Vice President.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of PacifiCorp d/b/a Pacific Power.

QUALIFICATIONS

Q. Please state your qualifications.

A. Please refer to Exhibit PAC/201 for my qualifications.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I sponsor the depreciation study performed for PacifiCorp attached hereto as Exhibit PAC/202 (Depreciation Study). The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of December 31, 2017. Based on the Depreciation Study, I recommend depreciation rates using the projected December 31, 2020 plant and reserve balances for approval. The proposed rates appropriately reflect the rates at which PacifiCorp's assets should be depreciated over their useful lives and are based on the most commonly used methods and procedures for determining depreciation rates.

Q. Can you summarize the results of your Depreciation Study?

A. Yes. The depreciation rates as of December 31, 2017 appropriately reflect the rates at which the values of PacifiCorp's assets have been consumed over their useful lives to date. These rates are based on the most commonly used methods and procedures for determining depreciation rates. The life and salvage parameters are based on widely used techniques and the depreciation rates are based on the average service life procedure and remaining life method. Therefore, the depreciation rates set forth on pages VI-4 through VI-21 of Exhibit PAC/202 represent the calculated rates as of December 31, 2017.

DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Q. Did you prepare the Depreciation Study filed by PacifiCorp in this proceeding?

A. Yes. I prepared the Depreciation Study submitted by PacifiCorp with its filing in this proceeding. The Depreciation Study is titled: "Depreciation Study – Calculated

Annual Depreciation Accruals Related to Electric Plant as of December 31, 2017." This report sets forth the results of my Depreciation Study for PacifiCorp.

Q. In preparing the Depreciation Study, did you follow generally accepted practices in the field of depreciation valuation?

A. Yes.

Q. Are the methods and procedures of this Depreciation Study consistent with past practices?

A. The methods and procedures of this Depreciation Study are the same as those used in past studies of this company as well as others before the Public Utility Commission of Oregon (Commission). Depreciation rates are determined based on the average service life procedure and the remaining life method.

Q. Please describe the contents of the Depreciation Study.

A. The Depreciation Study is presented in nine parts: Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII, and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

The table on pages VI-4 through VI-21 of the Depreciation Study presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2017, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate and simulated plant analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2017. Finally, the section in the Appendix on Page 1393 presents the recommended depreciation rates and parameters as of December 31, 2020.

Q. Please explain how you performed the Depreciation Study.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and reasonable manner.

Q. How did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the service life and net salvage characteristics for each depreciable group.

A. The service life and net salvage study consisted of compiling historical data from records related to PacifiCorp's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. What historical data did you analyze for the purpose of estimating service life characteristics?

A. I analyzed the company's accounting entries that record plant transactions during the period 1937 through 2017, however, the earliest year of data varied by account. The transactions included additions, retirements, transfers, sales, and the related balances.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method for most plant accounts. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the company during the period of time covered by the Depreciation Study.

Q. Please describe how you used the retirement rate method to analyze PacifiCorp's service life data.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa-type survivor curves were used to perform these interpretations.

Q. Did you use any other methods to analyze service life data?

A. Yes. For most distribution assets in Idaho and Utah, the company accounting records have not maintained the vintage of each transaction. Therefore, the simulated plant record method was utilized to determine life characteristics.

Q. What is an "Iowa-type Survivor Curve" and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 60-R2 indicates an average service life of sixty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 2, for the mode (possible modes for R type curves range from 1 to 5).

Q. What approach did you use to estimate the lives of significant facilities structures such as production plants?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to the replacement of elements of the facility, such as, for a building, the retirements of plumbing, heating, doors, windows, roofs, etc., that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. Has Gannett Fleming used this approach in other proceedings?

A. Yes, we have used the life span technique in performing depreciation studies presented to and accepted by many public utility commissions across the United States and Canada. This technique is currently being used by PacifiCorp in the same manner recommended in this case.

Q. What are the bases for the probable retirement years that you have estimated for each facility?

A. The bases for the probable retirement years are life spans for each facility that are based on judgment, the life assessment study and incorporate consideration of the age, use, size, nature of construction, management outlook, and typical life spans experienced and used by other electric utilities for similar facilities. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirements of these facilities are not yet subject to specific management plans. Such plans would be premature. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the facility's life span.

Q. Have you physically observed PacifiCorp's plant and equipment during your past depreciation studies?

A. Yes. I made field reviews of PacifiCorp's property as part of the past study in May and June 2012 to observe representative portions of plant. Field reviews are conducted to become familiar with company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe how you estimated net salvage percentages.

A. I estimated the net salvage percentages by incorporating the historical data for the period 1992 through 2017 and considered estimates for other electric companies. The net salvage percentages are based on a combination of statistical analyses and informed judgment. The statistical analyses consider the cost of removal and gross salvage ratios to the associated retirements during the 26-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. Were the net salvage percentages for generating facilities based on the same analyses?

A. Yes, for the interim analyses. The net salvage percentages for generating facilities were based on two components, the interim net salvage percentage and the final net salvage percentage. The interim net salvage percentage is determined based on the historical indications from the period, 1992–2017, of the cost of removal and gross salvage amounts as a percentage of the associated plant retired. The final net salvage or dismantlement component was determined based on the assets anticipated to be retired at the concurrent date of final retirement.

Q. Have you included a dismantlement component into the overall recovery of generating facilities?

A. Yes. A dismantlement component has been included to the net salvage percentage for steam and other production facilities. There is a separate decommissioning reserve for small hydro facilities which are soon to be retired, as the dismantlement component for hydro facilities in the study is zero.

Q. Can you explain how the dismantlement component is included in the Depreciation Study?

A. Yes. The dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of PacifiCorp, it was determined that the dismantlement or decommissioning costs for steam production and other production facilities is best calculated on a $/KW factor based on surviving plant at final retirement. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. The detailed calculation for each location is set forth on pages VIII-2 through VIII-287 of Exhibit PAC/202.

Q. Please describe the second phase of the process that you used in the Depreciation Study in which you calculated composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group, using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please use an example to illustrate how the annual depreciation accrual rate for a particular group of property is presented in your Depreciation Study.

A. I will use Account 353, Station Equipment, as an example because it is one of the largest depreciable mass accounts and represents approximately nine percent of depreciable plant.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1924 through 2017 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1924–2017 and 1988–2017 experience bands are presented on pages VII-95 through VII-97 of the report. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-95 shows $2,133,875 retired at age 0.5 with $2,347,756,170 exposed to retirement. Consequently, the retirement ratio is 0.0009 and the surviving ratio is 0.9991. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 58-S0 on page VII-94.

The net salvage percent is presented on pages VIII-49 and VIII-50. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1992 through 2017. The 26-year period experienced $20,503,595 ($8,621,261 – $29,124,856) in net salvage for $179,971,886 plant retired. The result is negative net salvage of eleven percent ($20,503,595/$179,971,886). Although recent trends have shown indications more negative, it was determined that based on industry ranges and company expectations, that negative ten percent was the most appropriate estimate.

My calculation of the annual depreciation related to the original cost at December 31, 2017, of electric plant is presented on pages IX-299 through IX-301. The calculation is based on the 58-S0 survivor curve, ten percent negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life, and annual accrual. These totals are brought forward to the table on page VI-18.

CONCLUSION

Q. Was the Depreciation Study filed by PacifiCorp in this proceeding prepared by you or under your direction and control?

A. Yes.

Q. Does your Depreciation Study recommend new depreciation rates based on December 31, 2020 plant and reserve balances?

A. Yes. The depreciation accrual rates set forth in the Appendix to Exhibit PAC/202 represent the rates most applicable in this proceeding. These rates utilize all the same methods and procedures as described in the Depreciation Study but apply the parameters to the projected December 31, 2020 plant and reserve balances. The projected plant balance as of December 31, 2020 and the bring forward of the book reserve from December 31, 2017 to December 31, 2020 properly establish the most reasonable rate base when the rates will go into effect. Thus, the rates in the Appendix are the recommended depreciation accrual rates.

Q. Were there alternative depreciation rates for coal-fired plant determined for Oregon as compared with the company's other jurisdictions?

A. Yes. In the company's previous depreciation proceedings in Oregon, the Commission rejected a provision in a stipulation between the company and Commission Staff proposing to extend the depreciable lives of PacifiCorp's coal-fired generating facilities. Other jurisdictions approved longer depreciable lives for these plants. Therefore, in this case, the company used the developed accumulated depreciation based on shorter depreciable lives that the Commission ordered in the previous case. The company conducted a separate Oregon-specific calculation for coal-fired plants reflecting the developed accumulated depreciation from past cases as of December 31, 2017 and as of December 31, 2020. The results of the two calculations are set forth in Exhibit PAC/203 "Oregon Steam Production Plant."

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

Arizona Corporation Commission
DOCKETED

FEB 24 2017

DOCKETED BY GB

TOM FORESE – Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD W. DUNN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322 DECISION NO. 75975 **OPINION AND ORDER**

DATES OF HEARING:	September 8-22, 2016
PLACE OF HEARING:	Tucson, Arizona
PUBLIC COMMENTS:	August 31, 2016
PLACE OF PUBLIC COMMENTS:	Tucson, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
IN ATTENDANCE AT PUBLIC COMMENT:	Doug Little, Commissioner Bob Stump, Commissioner Bob Burns, Commissioner Andy Tobin, Commissioner
APPEARANCES:	Mr. Michael W. Patten, SNELL & WILMER, LLP, and Mr. Bradley S. Carroll, Tucson Electric Power Company, for Tucson Electric Power Company; Mr. Thomas Loquvam, PINNACLE WEST CAPITAL CORPORATION LAW DEPARTMENT, on behalf of Arizona Public Service Company;

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is less than TEP's initial request, that no reduction be made to the proposed allocation to the Residential class and that the reduction be applied to the General Service ("GS"), Large General Service ("LGS") and Large Power Service ("LPS") classes.[21] In Direct Testimony, DOD recommended an OCRB rate of return of 6.74 percent, based on a cost of equity of 9.3 percent, cost of debt of 4.32 percent, and the actual test year capital structure of 48.69 percent equity and 51.31 percent debt.[22] DOD recommended a FVROR of 5.0 percent, which resulted in a recommended increase in revenue of $76.0 million.[23]

SWEEP recommended that TEP's approved EE program budget of $23 million be recovered in base rates rather than through the Demand Side Management ("DSM") adjustor.[24] All else being equal, SWEEP's recommendation would increase operating expenses, and thus affect the revenue increase, although with the DSM surcharge reduced by a commensurate amount, the impact on the rate payers' bills would not change.

Although other parties had recommendations concerning the CCOSS, revenue allocation, proposed tariffs and rate design, as well as various other issues, they did not provide Direct Testimony concerning specifics of the revenue requirement.[25]

Following notice of settlement discussions, some of the parties to this proceeding entered into a settlement agreement dated August 15, 2016 ("Settlement Agreement" or "Agreement") that purports to resolve the revenue requirement portion of the proceeding. The Settlement Agreement was entered into by: TEP, RUCO, Freeport and AECC, Kroger, Wal-Mart, AIC, Sierra Club, WRA, and Staff. The Settlement Agreement was not entered into by all parties to the proceeding, and it did not address all issues, leaving open the allocation of revenue among the rate classes, rate design, the LFCR, PPFAC, net metering, and the Buy-Through Tariff, as well as other issues discussed herein.

II. The Settlement Agreement

A. Terms of the Agreement

A copy of the Settlement Agreement is attached hereto as Exhibit A. The Agreement provides for a non-fuel revenue requirement of $714,022,900 which is a base rate revenue increase of $81.5

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[21] Ex DOD-1 Brudaker Dir at 24-25.
[22] Ex DOD-3 Gorman Dir at 3.
[23] *Id.* at MPG-1.
[24] Ex SWEEP-1 Schlegel Dir at 8-9.
[25] Wal-Mart provided Direct Testimony related to the importance of the Cost of Capital. Ex Wal-Mart-1 Tillman Dir.

million over adjusted test year non-fuel retail revenues.[26] The average base fuel rate is to be set at \$0.032559 to recover a total of \$289,147,243 in base fuel revenues. The result is a total revenue requirement of \$1,003,170,143.[27]

The parties supporting the Settlement Agreement have agreed that TEP's jurisdictional FVRB used to establish rates should be \$2,843,985,854, based on the average of an OCRB of \$2,045,203,460 and RCND of \$3,633,027,972.[28]

When it filed its Rate Application, TEP was in the process of acquiring a 50.5 percent interest in the Springerville Generating Station Unit 1 ("SGS 1").[29] TEP originally proposed to recover the costs of operating SGS 1 through its PPFAC. The Settlement Agreement provides that the annual operating costs of approximately \$15,243,913 will be recovered through non-fuel rates, but that this portion of the rate increase should not be effective until after the purchase is completed and a final Order issued.[30] The \$15.2 million of operating costs associated with SGS 1 is included in the \$81.5 million increase reflected in the Settlement Agreement. By providing for the recovery of the costs of SGS 1 in base rates instead of the PPFAC, the effect on the overall revenue increase is neutral. TEP agreed not to request rate base treatment for the 50.5 percent share in SGS 1 until its next general rate case.[31]

The Settlement Agreement provides for a capital structure of 49.97 percent long-term debt and 50.03 percent common equity. The proponents have agreed to a return on common equity ("ROE") of 9.75 percent and an embedded cost of long-term debt of 4.32 percent, resulting in a WACC of 7.04

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[26] Settlement Agreement at ¶ 2.1.
[27] *Id.* at ¶ 2.3.
[28] *Id.* at ¶ 2.5. Note that the FVRB in the Settlement Agreement overstates the average of the OCRB and RCND.
[29] In December 2014 and January 2015, TEP purchased leased interests in SGS 1 totaling 35.4 percent for an aggregate purchase price of \$65 million, which brought TEP's ownership interest in the unit to 49.5 percent. Prior to January 1, 2015, TEP leased 100 percent of SGS 1 and owned an equity interest in one of the leases covering a 14 percent share of the unit. In its Application, TEP removed the lease costs from its revenue requirement and included adjustments to rate base and operating expenses to reflect the Company's 49.5 percent ownership interest. TEP sought approvals related to changes at the SGS, including an extended recovery period for leasehold improvements made to SGS common facilities as well as recovery of operating costs through the PPFAC for energy dispatched from the 50.5 percent co-owner share of SGS 1, to the extent that capacity is available to meet retail customer needs. Ex TEP-1 Application at 8.
[30] Settlement Agreement at ¶2.4. During the Hearing, Mr. Sheehan testified that the purchase of the SGS 1 had received FERC approval and the transaction was expected to close on September 16, 2016. Transcript of the Hearing ("Tr.") at 1242. TEP filed notice on September 26, 2016, that it had completed the purchase.
[31] Settlement Agreement at ¶5.2. The leasehold improvements associated with the 50.5 percent interest in SGS 1 will be updated in the OCRB at the Net Book Value as of December 31, 2016, and amortization of these assets will continue as approved in TEP's last rate case. *See* Decision No. 73912 (June 27, 2013).

percent. The Settlement provides for a FVROR of 5.34 percent, which includes a rate of return on the fair value increment of 1.0 percent.[32]

The Settlement Agreement accepts the depreciation and amortization rates as proposed by TEP in its Rebuttal Testimony except: (1) the rates for the San Juan Generating Station ("San Juan") will be adjusted to reflect a depreciable life of TEP's total investment, including the Balanced Draft project, at San Juan Unit 1, or six remaining years; (2) $90 million of excess depreciation reserves will be transferred to San Juan Unit 1; and (3) depreciation rates on TEP's distribution plant are reduced to offset the increase in depreciation expense for San Juan Unit 1.[33]

The Settlement Agreement provides that TEP will write down the Net Book Value of its headquarters building by $5 million, resulting in a $5 million reduction to OCRB, within 30 days of the issuance of a final order in this proceeding. In return, the signatories to the Settlement Agreement agree that they will not seek alternate rate treatment or additional write-down of the headquarters building in future rate proceedings.[34]

The Settlement Agreement provides that post-test year plant in the amount of $49.6 million and post-test year renewable generation plant of $4.8 million that is verified and in-service as of June 30, 2016, will be included in the Company's OCRB.

B. Arguments in Favor of Settlement Agreement

1. TEP

TEP states that the Settlement Agreement is supported by diverse interests and is the product of an open, transparent process that balances the interests of a variety of stakeholders.[35] TEP argues that the Agreement's terms are fair and reasonable. The Company notes that the non-fuel revenue increase agreed to in the Settlement Agreement is $44.3 million less, or approximately 65 percent, of its original request in the Application (when the operating costs of SGS 1 that would have been

[32] Settlement Agreement at ¶¶ 3.1 – 3.3.
[33] *Id.* at ¶ 4.1. By accelerating depreciation on San Juan Unit 1, the parties believe that it will be easier for TEP to make a decision about the continued operation of this unit in 2022 when the Fuel Supply Agreement and Plant Participation Agreement expire.
[34] *Id.* at ¶ 6.1
[35] TEP Opening Brief at 3.

recovered it the PPFAC are factored in).[36] In addition, TEP states that the Settlement Agreement reduces the Company's requested OCRB by $59.5 million.[37]

TEP claims that the Settlement Agreement provides momentum to its generation diversification strategy by recovering non-fuel operating costs related to its 50.5 percent acquisition of SGS 1 and reducing the book value and depreciation lives related to its existing coal generation assets.[38] By modifying the depreciation reserves and rates for San Juan Unit 1, TEP's investment in the unit will be almost fully depreciated by 2022 when the current coal supply contract and participation agreement expire. TEP states that this, along with the additional SGS 1 capacity, gives TEP more flexibility in its resource portfolio after 2022, and allows TEP to exit San Juan without large cost impacts on customers.[39] TEP states that the acquisition of the remainder of SGS 1 means ratepayers benefit from a reliable, low-cost base load resource that utilizes TEPs existing bulk transmission assets and supports a significant portion of the Company's ancillary service requirements.

TEP also argues that the Settlement Agreement's revenue requirement will help the Company maintain or improve its investment-grade credit ratings.[40] Other credit-supportive aspects of the Agreement, according to TEP, include an authorized ROE that is comparable to the recent ROEs approved for other vertically integrated investor-owned utilities; a capital structure that reflects the significant improvement in equity since the last rate case and the acquisition of UNS Energy by Fortis; and recovery of non-fuel operating and maintenance costs related to the recent purchase of the remaining 50.5 percent of SGS 1.[41]

The Settlement Agreement adopts TEP's capital structure at the end of the test year consisting

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[36] *Id.* at 4.

$ in millions	Initial Position	Settlement	Change
Non-fuel Base Rate Increase	$109.50	$66.30	-$43.2
Treatment of Non-Fuel O&M related to 50.5 % of SGS 1:			
PPFAC Recovery	$16.30	$0.00	-$16.30
Non-fuel Base Rates	$0.00	$15.20	$15.20
Total	$125.80	$81.50	-$44.30

[37] No party objected to the Settlement's proposed OCRB, except that EFCA has argued that $16,000 associated with TORS should not be included.

[38] TEP Opening Brief at 6; Ex TEP-6 Hutchens Settlement at 5.

[39] TEP Opening Brief at 6.

[40] *Id.* TEP is currently rated A3 by Moody's Investor Services and BBB+ by Standard & Poor's. Ex TEP-6 Hutchens Settlement at 4.

[41] Ex TEP-6 Hutchens Settlement at 4.

of 49.97 percent long-term debt and 50.03 percent common equity; an ROE of 9.75 percent (compared to the Company's original requested ROE of 10.35 percent); and a fair value increment rate of return of 1.0 percent, compared to TEP's originally requested 1.42 percent. TEP states that the impact of these elements reduces the Company's requested non-fuel revenue increase by approximately $15.5 million.[42]

TEP argues that the Settlement's 9.75 percent ROE is within the approved ROEs of the proxy groups used by the only party who challenged the Settlement's finding.[43] TEP argues that the Settlement ROE of 9.75 percent is appropriate as compared to the 9.5 percent ROE authorized for UNSE because TEP has a much larger generation fleet that includes a significant amount of coal-fired generation and the inherent risk associated with increased economic regulation.[44] TEP explains that the capital structure adopted in the Settlement Agreement recognizes that TEP redeemed certain bonds several weeks after the end of the test year.[45] TEP argues that in recognizing that TEP was legally obligated to redeem the bonds, the Settlement Agreement accounts for known and measurable changes to the test year capital structure, and that the capital structure is not based on a transaction that "may" or "may not" occur.[46]

TEP also argues that the 1.0 percent return on the fair value increment of rate base is supported by the record and consistent with prior Commission approaches to the fair value increment. In Ms. Bulkely's Rebuttal Testimony, she calculated the return on the fair value increment to be 1.07 percent, and Staff's witness Mr. Parcell calculated the fair value increment (real risk-free rate) to be as high as 1.42 percent. Based on the record, TEP argues that the 1.0 percent compromise is reasonable.[47]

Further, TEP states that the Settlement Agreement reduces TEP's pro forma operating expenses by $22.6 million over the Company's initial request. The more significant adjustments normalize generation overhaul and outage expenses based on the most recent six years of actual data; exclude the wage and payroll tax increase associated with anticipated 2017 non-union wage increases; recover only

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[42] TEP Opening Brief at 7.
[43] *Id. citing* Ex DOD-4 Forman Surr, Ex MPG-24. TEP states the ROEs of Mr. Gorman's proxy group ranged from 10.3 percent to 9.3 percent, with an average of 9.73 percent.
[44] Ex TEP-12 Bulkley RJ at 5; Tr. at 368.
[45] Ex TEP-12 Bulkley RJ at 9.
[46] TEP Opening Brief at 8.
[47] *Id.* at 8.

50 percent of the normalized cost associated with the Company's Short Term Incentive compensation plan; caps rate case expense at $1 million to be amortized over four years; remove expenses associated with the Company's Long Term Incentive compensation plan; reduce test year legal costs by $1.1 million; and conform changes to depreciation and income tax expenses associated with agreed upon depreciation rates and rate base changes.[48]

TEP asserts that the depreciation modifications are consistent with TEP's last rate case order in which the Commission acknowledged the reasonableness of applying excess depreciation reserves to offset the effects of early production plant retirements.[49] TEP states that using excess distribution depreciation reserves will mitigate the rate impact of the San Juan Unit 1 accelerated depreciation resulting from shortening the life to six years. TEP contends that given the uncertainty surrounding TEP's continued operation of San Juan Unit 1 after the expiration of the current Fuel Supply Agreement and Plant Participation Agreement in 2022, it is reasonable to shorten its expected useful life.[50]

2. AIC

AIC, a signatory to the Settlement, asserts that the Agreement is both in the public interest and beneficial to the financial health of the Company.[51] AIC asserts that although the agreed revenue requirement is 26 percent lower than the Company's original request, it is a reasonable compromise considering the starting positions of the parties to this case. AIC states that investors and credit rating agencies look favorably on settlement agreements because they resolve issues that would otherwise result in protracted litigation and regulatory delay. AIC contends that adopting the Settlement would be further indication of an improved regulatory climate conducive for investment in Arizona's utilities.

3. RUCO

RUCO argues that the Settlement Agreement is in the public interest for each of the following benefits:

(1) The revenue increase of $81.5 million includes $15.2 million related to the non-fuel operating costs associated with the acquisition of the 50.5 percent share of the SGS 1

[48] *Id.* at 10; Ex TEP-23 Dukes Settlement at 3-4.
[49] Ex TEP-23 Dukes Settlement at 6.
[50] *Id.*
[51] AIC Opening Brief at 2.

(which originally the Company proposed be included in the PPFAC); thus, according to RUCO, the actual revenue increase is $66.3 million.[52]

(2) A permanent $5 million reduction to OCRB from the write down of the Net Book Value of the headquarters building.

(3) An $18.1 million reduction in post-test year plant being included in rate base.

(4) The adjustment of the depreciation rates for San Juan to reflect a depreciable life of six years, and the transfer of $90 million of excess distribution reserves to offset the change and to protect rate payers.[53]

(5) Lower authorized operating expenses including: the application of a six-year historical average of outage expenses; exclusion of increased 2017 payroll expenses for non-classified employees; a 50/50 sharing of short-term incentive compensation; rate case expense of $1 million normalized over four years; and removal of $1.1 million associated with litigation.

(6) The adoption of a cost of equity of 9.75 percent as compared to the 10.35 percent originally sought by the Company.

RUCO argues that the Settlement Agreement is a fair and reasonable resolution which benefits the Company's ratepayers while also providing the Company with a reasonable opportunity to earn its fair rate of return.[54]

4. AECC/Freeport/NS

AECC/Freeport/NS support the Settlement Agreement as a fair compromise of several contested issues, and a clear benefit to ratepayers due to the reduced revenue increase.[55]

5. Wal-Mart

Wal-Mart signed the Settlement Agreement, and notes that it is the result of arms-length negotiations between the parties, and adequately addresses the revenue requirement issues Wal-Mart raised in its testimony.[56]

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[52] RUCO Opening Brief at 3; Ex RUCO-5 Michlick Surr Attachment A at 4.
[53] Ex RUCO-5, Attachment A at 3.
[54] RUCO Opening Brief at 4.
[55] AECC/Freeport/NS Opening Brief at 2.
[56] Wal-Mart Opening Brief at 2; Ex Wal-Mart-3 Tillman.

6. Kroger

Kroger signed and fully supports the Settlement Agreement, which it states is the product of several rounds of negotiations between the Company and signatories, and reasonably balances the interests of the Company and its ratepayers.[57]

7. Sierra Club

Sierra Club's interest in this proceeding focused on the planned depreciation schedule for TEP's share of the San Juan Unit 1. Sierra Club signed the Agreement because the accelerated depreciation schedule for San Juan Unit 1 synchs with the end of the coal supply contract for the plant, and is the latest likely date that the unit will cease operation. Sierra Club asserts that accelerating the depreciation of San Juan Unit 1 is in the public interest because the entire San Juan plant is facing increasingly difficult economic conditions, and accelerating depreciation to coincide with its expected retirement date will ensure that only customers who receive power from San Juan will pay for the plant. Sierra Club states that the Settlement Agreement satisfactorily resolved all issues raised by Sierra Club testimony, and Sierra Club recommends that the Commission approve the Agreement as in the public interest.[58]

8. SAHBA

SAHBA did not file testimony in this proceeding and was not a signatory to the Settlement Agreement, however, SAHBA supports the settlement result of an $81.5 million non-fuel revenue requirement. SAHBA believes that it is important that TEP be in a position to continue to provide safe, adequate and reliable electric service, and presumes based on the Company's agreement to the Settlement, that it provides TEP with the support it needs to continue to provide such level of service.[59]

9. WRA

WRA signed and supports the Settlement Agreement for its treatment of the San Juan Unit 1.[60]

10. Staff

Staff asserts that the Settlement Agreement was the collaborative effort of parties with divergent

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[57] Kroger Opening Brief at 2.
[58] Sierra Club Opening Brief at 2.
[59] SAHBA Opening Brief at 2.
[60] SWEEP/WRA/ACAA Opening Brief at 21.

interests, working to narrow the contested issues in this proceeding.[61] Staff states that the one-day settlement conference was open, transparent and conducted at arm's length, with each participant given an opportunity to advance its position. Staff states that each of the signatories compromised on vastly different positions. Staff argues the Settlement Agreement furthers the public interest because it addresses TEP's revenue needs, promotes the convenience, comfort and safety, and preservation of health of the employees and patrons of TEP, resolves issues, and avoids litigation expense and delay.[62]

C. Arguments Against the Settlement Agreement

1. Capital Structure and Cost of Capital in Settlement is Unreasonable

a. DOD

DOD did not join the Settlement because it believes the revenue requirement is excessive and will produce rates that are not just and reasonable.[63] Specifically, DOD asserts that the Settlement is based on an inflated ROE and FVROR, and that the revenue requirement should be reduced by at least $14.1 million.[64] DOD argues that the Settlement's agreed 9.75 percent ROE compares unfavorably to the industry average of authorized returns of 9.5 percent, and the record does not support a FVROR of 5.34 percent in combination with an ROE of 9.75 percent.[65] As shown below, DOD asserts that no non-Company witness recommended an ROE greater than 9.5 percent.[66]

Party	ROE Range/(Rec.)	FVROR
TEP (Bulkley)	10.00 %[67]	5.69%
Staff (Parcell)	9.2%-9.5 % (9.35%)	5.00%
DOD (Gorman)	8.9%-9.7% (9.3%)	5.00%
RUCO (Mease)	7.91%-9.65% (9.2%)	5.20%
Wal-Mart (Tillman)	Max 9.50%	N/A

Based on the results of his Discounted Cash Flow ("DCF"), Capital Asset Pricing Model

[61] Staff Opening Brief at 6-7.
[62] Ex S-20 Abinah Settlement Test. at 8.
[63] DOD Opening Brief at 2.
[64] DOD Reply Brief at 1. According to the DOD, $11.1 million is attributed to overstating the rate of return, and $3.0 million is due to using a pro forma capital structure. *Id.* at 3.
[65] DOD Reply Brief at 1.
[66] DOD Opening Brief at 3.
[67] 10.35 percent pre-Settlement.

and/or unnecessary costs. Furthermore, Staff believes that a review of assets valued at $16,000 would be a waste of Commission resources. Staff believes that once the program is more fully installed, a prudency review would better serve its purpose. Staff submits "that the lack of a prudency review of the $16,641 installed TORS program should not prevent its inclusion in rate base under the present circumstances," and suggests that EFCA's recommendation is "absurd" given the fact that TEP has a FVRB of $2.8 billion, and that the TORS program is a pilot that the Commission approved with significant reporting requirements.[113]

D. <u>Analysis and Conclusions Regarding Settlement Agreement</u>

The proposed Settlement Agreement only resolves the revenue requirement portion of TEP's Rate Case. Although it was signed by only 11 of the 30 parties in this proceeding, those 11 represent a variety of interests, including large industrial customers, residential ratepayers, and environmental interests. Only the DOD took issue with one of the foundations of the Agreement.

The Settlement Agreements provides for a FVRB of $2.848 billion. This conclusion is $38 million less than Staff's recommendation, $266 million greater than RUCO's recommendation and $60 million less than the Company's original FVRB position.[114] No party, other than EFCA which opposes including TORS assets in rate base, objected to rate base balances in the Settlement. Given the pre-Settlement testimonies, the Settlement Agreement's position on rate base is reasonable and should be adopted.

We take no position at this juncture about the propriety of including TORS assets in rate base. The Commission approved the TORS program as a $10 million pilot project in the belief that the public interest would be served by exploring how such a program could benefit Renewable Energy Standard Tariff ("REST") compliance. The $16,000 TORS asset included in the $2.0 billion OCRB approved as part of the Settlement is immaterial to the determination of the revenue requirement or rates. In TEP's next rate case the TORS pilot project should be fully implemented, and at that time, we will determine if inclusion of those assets in rate base is appropriate. We concur with Staff that to require a prudency review of one TORS asset would not have been an efficient use of Commission resources

[113] Staff Reply Brief at 13.
[114] The specific rate base adjustments are set forth in Attachment A to the Settlement Agreement.

and would not have provided useful information on the entirety of the TORS program. Our decision to defer a finding on whether or not TORS assets should be included in rate base should not be seen as precedent for their ultimate inclusion.

Given the above, we find that a FVRB of $2,839,115,716, which is the average of the agreed OCRB and RCND rate base, is fair and reasonable.[115] This amount is $4,870,138 less than the figure included in the Settlement Agreement.

Based on a Fair Value Rate of Return of 5.35 percent, the Settlement Agreement provides for an $81.5 million non-fuel base rate increase, resulting in a $714,022,900 total non-fuel revenue requirement.[116]This reflects an 8.8 percent increase over adjusted test year revenues of $921,672,222. Because the corrected FVRB does not impact the agreed OCRB, and the rate of return on the difference between FVRB and OCRB is only 1.0 percent, the revenue impact of the correction is only $79,008. This amount is *de minimis* in the context of the agreed non-fuel revenue requirement increase of $81.5 million. Accordingly, we approve the agreed-upon revenue increase of $81.5 million set forth in the Settlement Agreement.

The $81.5 million increase is $44.3 million less than the $125.8 million that the Company originally requested.[117] It is $32.1 million greater than Staff's position in Direct Testimony, $64.1 million greater than RUCO's direct case recommendation, and $5.5 million greater than DOD's direct case. The operating expense adjustments agreed to in the Settlement are set forth in Attachment A thereto. The Settlement's proposed non-fuel increase is premised on a capital structure consisting of 49.97 percent long-term debt and 50.03 percent equity, a FVROR of 5.34 percent, which is based on a return on equity of 9.75 percent, and embedded cost of long-term debt of 4.32 percent, which results in a WACC of 7.04 percent. The rate of return on the fair value increment in the Settlement Agreement is 1.0 percent.

DOD believes that a 9.75 percent COE and return on the fair value increment of 1.0 percent are too high, and that the actual test year end capital structure consisting of 48.69 percent common equity

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[115] Final Schedule B-1.
[116] Ex TEP-1 Settlement at ¶2.1.
[117] Ex TEP-23 Dukes RJ at 2-3.

and 51.31 percent long-term debt should be utilized. DOD's recommended COE is 0.25 percent less than the Settlement Agreement.

The Settlement utilizes the actual test year capital structure, adjusted for the retirement of bonds that occurred shortly after the test year. The evidence supports the conclusion that TEP was obligated to redeem the bonds and that the redemption process was in place prior to the end of the test year. The pro forma adjustment represents a known and measurable change and warrants the use of the Settlement's agreed capital structure.

DOD criticizes certain assumptions in the Company's COE analysis, but the Settlement Agreement reflects a COE that is 0.25 less than the Company's rebuttal position and 0.6 percent less than the Company's original request. The agreed 9.75 percent COE is 0.05 percent higher than DOD's recommended cost based on the DCF method. The evidence shows that the Settlement's proposed 9.75 percent cost of equity is within the range of authorized equity returns for vertically integrated utilities in the proxy group which in 2015 ranged from 9.3 percent to 10.3 percent, with a median of 9.70 percent.[118] The Settlement's cost of equity is .25 percent higher than that recently approved for TEP's sister company UNSE, but TEP owns a much larger fleet of generation assets that still consists of a resource mix comprised 50 percent of coal, which exposes TEP to greater risk than faced by UNSE.[119] The Settlement Agreement's 9.75 percent COE is reasonable under the circumstances of this case.

DOD believes that the difference between the OCRB and RCND represents cost free capital, and that there should not be an additional return included for this fair value increment.[120] As an alternative, DOD utilized its underlying assumptions but applied the Company's method of determining the fair value increment, to compute a fair value increment return of 0.46 percent.[121] Staff has argued in this case, that the concept of cost of capital is designed to apply to OCRB, but that when the concept of FVRB is incorporated, the link between rate base and capital structure is broken, as the amount of FVRB that exceeds OCRB is not financed with investor-supplied funds, and it could be

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[118] Ex DOD-4 Gorman Surr at MPG-24.
[119] Tr. at 368; Ex TEP-24 Sheehan Dir at 2.
[120] Ex DOD-3 Gorman Dir at 70-71. DOD argues that the Net Operating Income should be set by either an original cost or a fair value rate-setting methodology. According to DOD, in the OCRB Rate of Return the expected growth rate in asset values is included in the rate of return and in a fair value methodology, expected growth in the value of assets is picked up in the growth to the rate base itself, and not rate of return.
[121] *Id.* at MPG-21.

argued has no cost.[122] However, Staff prepared an alternative analysis for the fair value increment based on a risk-free rate, and recommended a fair value rate of return of 0.7 percent.[123]

In recent rate cases, the Commission has authorized returns that recognize the methodology utilized by the Company and Staff to provide a positive return for the fair value increment. The Settlement Agreement adopts a fair value increment rate of return that is 0.3 percent greater than Staff's recommendation and 0.42 percent less than originally proposed by TEP. It is based on a methodology utilized by the Commission in the past and is not unreasonable as a negotiated resolution.

Under the totality of circumstances in this case, including the rate design issues resolved later, we find that a cost of equity of 9.75 percent is reasonable.

SWEEP is the only party that proposed to include the costs of the Company's authorized EE and DSM programs in base rates. While we do not disagree that EE is an important resource for the Company, we have not been presented with a compelling reason to change the current structure for recovering their costs.

We find that the terms of the Settlement Agreement were the result of open and transparent discussions, and when corrected to reflect the appropriate FVRB, are fair and reasonable. Thus, we approve the Settlement Agreement as corrected.

We also believe that customer education and transparency in utility operations and ratemaking is important. SWEEP's proposal to communicate information about resource mix and costs is helpful to that process. TEP did not oppose the idea. Having the information available in a simple format as suggested by SWEEP should not be costly. Thus, we direct TEP to file, within 120 days of the Order in this proceeding, a proposal to provide information to customers on the ratepayer costs of major energy resources via the web, and how to communicate with consumers about accessing the data.

III. Revenue Allocation

A. TEP

TEP states that one of its goals in this rate case is to reduce interclass subsidies by bringing revenue recovery from each class closer to its actual cost of service, however, in conformance with the

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122 Ex S-3 Parcel Dir at 43-45.
123 *Id.* at 47-49.

June 4, 2021

TO: Corinne O. Milinovich
Alliance of Western Energy Consumers'

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UM 2152
PGE Response to AWEC Confidential Data Request No. 024
Dated May 21, 2021

Request:

Please refer to the response to AWEC DR 005, confidential attachment "PGE data questions.pdf", which states "…[redacted]."

a. Did Mr. Spanos believe that [redacted] in Docket No. UM 1809? If no, what period and analysis does this statement continue from?
b. Does PGE currently believe [redacted] for Account Number 373.01 Street Lighting – Circuits – Other? If no, why not?

Response:

a. The discussion in AWEC DR 005, confidential attachment "PGE data questions.pdf" referenced in this data requests relates to Account 373.01, Street Lighting – Circuits – Other. As is the case for all accounts, life analysis is a combination of statistical analysis and informed judgment where informed judgment includes PGE plans and estimates of other utilities. In Docket No. UM 1809, PGE identified some missed retirements and the expectation for an increased level of retirements in the future. Most other electric utilities have an expected life of 40 years or less. Therefore, based on the informed judgment and PGE plans, Mr. Spanos believed the 40-year life was the most appropriate estimate for the account combined with the L2.5 survivor curve. This was not supported statistically since some retirements had not been recorded. Consequently, the statement was related to the fact that all of the catchup retirements were still not recorded as part of this study.
b. PGE also does not believe it is hard to justify when considering all of the key factors for determining life analysis and the nature of the assets in Account 373.01.

AWEC Data Request No. 024 is protected information subject to Protective Order No. 21-017.

Pages 2-3 of Cross-Exam Exhibit AWEC/209 contain Protected Information Subject to Order No. 21-017 and have been redacted in their entirety.

June 4, 2021

TO: Corinne O. Milinovich
Alliance of Western Energy Consumers'

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC
UM 2152
PGE Response to AWEC Confidential Data Request No. 023
Dated May 21, 2021

Request:

Please refer to the response to AWEC DR 005, confidential attachment "PGE data questions.pdf".

a. Please confirm that PGE intends to extend recovery of Colstrip asset retirement obligations to 2050.
b. If confirmed, why does PGE propose extending recovery to 2050?
c. What decommissioning costs are not recovered over the extended period? Why not?
d. Please confirm that PGE intended to accelerate the depreciable life of Colstrip steam assets to 2025. Please explain why PGE changed the proposed acceleration date from 2025 to 2027.

Response:

PGE does not consider this request to be confidential. As such, PGE is providing this response as public information.

a. Yes, PGE intends to recover costs associated with the Colstrip asset retirement obligations through 2050.
b. Environmental remediation activity related to the ARO is expected to occur through approximately 2050. This proposal matches the periods of recovery to the periods in which the work is performed.
c. Non-ARO costs related to plant decommissioning are not recovered over the extended period. These costs are primarily related to the deconstruction of Unit 3 and 4 structures and are included within the terminal retirement assumptions resulting in the weighted average net salvage percent of 4% for Colstrip steam production assets.
d. As described in the Colstrip Enabling Study provided in response to AWEC Data Request No. 008, Attachment 008-A, the analysis suggested that the removal of Colstrip from PGE's portfolio in 2025 provides customers the greatest reduction in the Integrated Resource Plan portfolio metrics of cost and risk. However, when considering other factors described in PGE's response to AWEC Data Request No. 018, PGE is proposing to accelerate the depreciable life of Colstrip to December 31, 2027.

September 28, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UM 2152
PGE Response to AWEC Data Request 046
Dated September 21, 2021

Request:

Please refer to the response to AWEC DR 5, confidential attachment "PGE data questions.pdf". Please provide the following data regarding account 373.01:

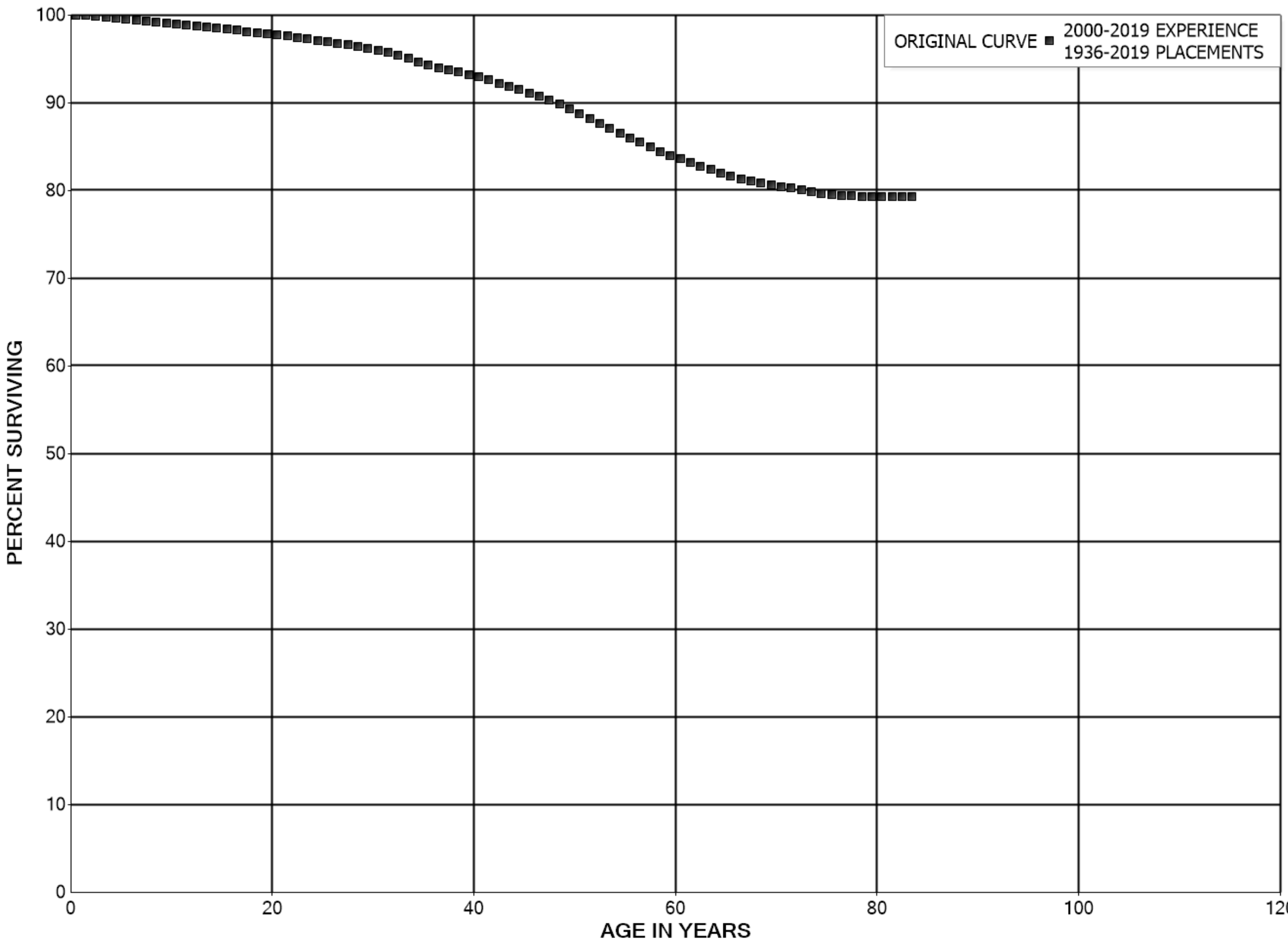
a. Did PGE produce an original life table or survivor curve for account 373.01?
b. If yes, please provide such data.
c. If yes, please explain why PGE did not produce such data with the Depreciation Report.
d. If no, please explain how PGE determined that this account had 80% of assets in service at 80 years of age and provide all supporting calculations and workpapers.
e. Please refer to the email from Ryan Van Oostrum dated September 30, 2020 12:53 PM. Please provide the analysis of street lighting discussed in this email.

Please refer to the email from Ryan Van Oostrum dated September 30, 2020 12:53 PM. How did the analysis of street lighting discussed in this email affect the percent of assets in service at 80 years of age for this account?

Response:

a. Yes.
b. Attachment 046-A provides the original life table and curve of the Company's historic data for account 373.01.
c. During the conduct of life analysis for the depreciation study, it was determined that the historic data were not representative of the future expectations for these assets. As was the case in the prior depreciation study, the assets in this subaccount have not had material retirements recorded as of December 31, 2019, so informed judgment has been used to properly assess the proper life estimation for this subaccount of street lighting. The 40 year average service life and 90 year maximum life was considered appropriate for street lighting circuits which is presented by the 40-L2.5 curve on page VII-170 of the Depreciation Study. Also, it should be noted that the depreciation data was provided in the input data to all parties.
d. Not applicable.
e. The analysis is provided as the attachment to this response referred to in part b.
f. The analysis referred to in the email did not affect the percent of assets in service in account 373.01 at 80 years of age.

PORTLAND GENERAL ELECTRIC
ACCOUNT 373.01 CIRCUITS - OTHER
ORIGINAL AND SMOOTH SURVIVOR CURVES



PORTLAND GENERAL ELECTRIC

ACCOUNT 373.01 CIRCUITS - OTHER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1936-2019 EXPERIENCE BAND 2000-2019

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,581,683	69	0.0000	1.0000	100.00
0.5	12,851,015	12,214	0.0010	0.9990	100.00
1.5	12,967,418	13,485	0.0010	0.9990	99.90
2.5	14,751,973	16,353	0.0011	0.9989	99.80
3.5	15,057,849	14,075	0.0009	0.9991	99.69
4.5	15,299,021	13,989	0.0009	0.9991	99.60
5.5	15,869,754	14,512	0.0009	0.9991	99.51
6.5	16,268,670	18,168	0.0011	0.9989	99.41
7.5	16,595,534	18,229	0.0011	0.9989	99.30
8.5	17,001,641	18,476	0.0011	0.9989	99.19
9.5	17,045,248	19,582	0.0011	0.9989	99.09
10.5	17,199,169	18,754	0.0011	0.9989	98.97
11.5	16,480,093	18,010	0.0011	0.9989	98.87
12.5	15,463,878	18,602	0.0012	0.9988	98.76
13.5	14,568,224	17,575	0.0012	0.9988	98.64
14.5	13,748,366	18,885	0.0014	0.9986	98.52
15.5	12,633,411	17,103	0.0014	0.9986	98.38
16.5	12,324,416	18,763	0.0015	0.9985	98.25
17.5	11,645,361	15,489	0.0013	0.9987	98.10
18.5	10,917,808	14,669	0.0013	0.9987	97.97
19.5	10,352,209	13,807	0.0013	0.9987	97.84
20.5	9,856,599	12,679	0.0013	0.9987	97.71
21.5	9,222,228	12,704	0.0014	0.9986	97.58
22.5	7,287,328	12,034	0.0017	0.9983	97.45
23.5	6,339,362	10,980	0.0017	0.9983	97.29
24.5	5,515,645	11,516	0.0021	0.9979	97.12
25.5	4,856,045	8,518	0.0018	0.9982	96.92
26.5	4,442,927	7,765	0.0017	0.9983	96.75
27.5	4,025,227	7,277	0.0018	0.9982	96.58
28.5	3,543,062	7,528	0.0021	0.9979	96.40
29.5	3,038,176	7,308	0.0024	0.9976	96.20
30.5	2,374,781	7,093	0.0030	0.9970	95.97
31.5	2,195,710	7,386	0.0034	0.9966	95.68
32.5	2,047,430	7,416	0.0036	0.9964	95.36
33.5	1,924,433	7,190	0.0037	0.9963	95.01
34.5	1,772,733	6,408	0.0036	0.9964	94.66
35.5	1,658,036	5,790	0.0035	0.9965	94.32
36.5	1,581,927	4,326	0.0027	0.9973	93.99
37.5	1,488,354	4,067	0.0027	0.9973	93.73
38.5	1,385,665	3,977	0.0029	0.9971	93.47

PORTLAND GENERAL ELECTRIC

ACCOUNT 373.01 CIRCUITS - OTHER

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1936-2019 EXPERIENCE BAND 2000-2019

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,223,047	3,891	0.0032	0.9968	93.20
40.5	1,033,482	3,639	0.0035	0.9965	92.91
41.5	848,915	3,320	0.0039	0.9961	92.58
42.5	800,508	3,274	0.0041	0.9959	92.22
43.5	763,315	3,119	0.0041	0.9959	91.84
44.5	706,105	2,908	0.0041	0.9959	91.47
45.5	638,016	2,767	0.0043	0.9957	91.09
46.5	581,609	2,730	0.0047	0.9953	90.69
47.5	535,394	2,768	0.0052	0.9948	90.27
48.5	482,494	2,673	0.0055	0.9945	89.80
49.5	434,166	2,563	0.0059	0.9941	89.30
50.5	396,713	2,459	0.0062	0.9938	88.78
51.5	365,037	2,312	0.0063	0.9937	88.23
52.5	339,102	2,189	0.0065	0.9935	87.67
53.5	312,756	1,984	0.0063	0.9937	87.10
54.5	285,905	1,801	0.0063	0.9937	86.55
55.5	258,478	1,574	0.0061	0.9939	86.00
56.5	230,582	1,424	0.0062	0.9938	85.48
57.5	205,305	1,228	0.0060	0.9940	84.95
58.5	180,015	952	0.0053	0.9947	84.44
59.5	155,063	785	0.0051	0.9949	84.00
60.5	129,692	638	0.0049	0.9951	83.57
61.5	109,862	517	0.0047	0.9953	83.16
62.5	88,114	424	0.0048	0.9952	82.77
63.5	66,472	304	0.0046	0.9954	82.37
64.5	52,535	218	0.0042	0.9958	82.00
65.5	41,666	167	0.0040	0.9960	81.65
66.5	33,282	118	0.0035	0.9965	81.33
67.5	25,928	66	0.0025	0.9975	81.04
68.5	18,759	43	0.0023	0.9977	80.83
69.5	13,612	37	0.0027	0.9973	80.65
70.5	9,564	20	0.0021	0.9979	80.43
71.5	5,628	10	0.0018	0.9982	80.26
72.5	2,445	7	0.0029	0.9971	80.11
73.5	1,105	3	0.0028	0.9972	79.88
74.5	758	2	0.0021	0.9979	79.66
75.5	495	1	0.0013	0.9987	79.49
76.5	339	0	0.0005	0.9995	79.39
77.5	259	0	0.0003	0.9997	79.35
78.5	122		0.0000	1.0000	79.33

PORTLAND GENERAL ELECTRIC

ACCOUNT 373.01 CIRCUITS - OTHER

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1936-2019 EXPERIENCE BAND 2000-2019

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	56		0.0000	1.0000	79.33
80.5	26		0.0000	1.0000	79.33
81.5	9		0.0000	1.0000	79.33
82.5	2		0.0000	1.0000	79.33
83.5					79.33

September 30, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UM 2152
PGE Response to AWEC Data Request 064
Dated September 23, 2021

Request:

In Exhibit PGE/200, Tooman-Batzler/2:7-21 in Docket UE 394, PGE states that Colstrip's isolated revenue requirement is $55.9 million and that "PGE requests an overall base business increase of approximately $59.0 million or 2.9%, including all Colstrip-related costs."

a) Please confirm that the $55.9 million figure assumes a Colstrip probable retirement date of 2027. If not confirmed, please identify the probable retirement date assumed for Colstrip.

b) Please update the $55.9 million figure in this testimony to reflect the Stipulation's proposal to fully depreciate Colstrip by the end of 2025.

c) Please identify what PGE's overall base business increase, including all Colstrip- related costs, would be in UE 394 if the Commission adopts AWEC's proposal to use excess reserves to buy down the entire undepreciated investment in Colstrip. Please state your answer in terms of total dollar and overall percentage increases.

Response:

PGE inadvertently missed to submit the response to this data request on the due date of September 30, 2021.

PGE objects to this data request on the basis that it is asking for new analysis, it is not relevant, and outside the scope of the depreciation study investigated in this docket. AWEC can submit this request as part of Docket No. UE 394.

Office of the Secretary
Service Date
November 18, 2013

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER TO CHANGE THE DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PROPERTY	**CASE NO. PAC-E-13-02** **ORDER NO. 32926**

On January 22, 2013, PacifiCorp dba Rocky Mountain Power ("Rocky Mountain" or "Company") submitted an Application seeking a Commission Order, pursuant to *Idaho Code* § 61-525 and Rule 52 of the Idaho Public Utilities Commission ("Commission") Rules of Procedure, for approval of proposed changes to depreciation rates applicable to Rocky Mountain's depreciable electric plant. The Company proposes an effective date of January 1, 2014 for its proposed changes.

On March 28, 2013, the Commission issued a Notice of Application and Intervention Deadline. *See* Order No. 32772. Subsequently, Monsanto Company ("Monsanto") and PacifiCorp Idaho Industrial Customers ("PIIC") were granted permission to intervene as a party. *See* Order Nos. 32773 and 32804.

On April 26, 2013, the Commission issued a Notice of Public Workshop. A public workshop was held on May 9, 2013, allowing interested parties the opportunity to discuss a possible settlement of the issues presented in this case.

On September 10, 2013, Rocky Mountain filed a settlement document ("Stipulation") with the Commission, including attachments, that proposes to settle the relevant issues in this case. The Stipulation was agreed to by representatives of the Company, Staff, Monsanto, and PIIC ("Parties").

THE APPLICATION

In its Application, RMP states that as a public utility operating under the Commission's jurisdiction its depreciation accounts must comply with the rates previously determined by the Commission. The Company's last depreciation Application, Case No. PAC-E-07-14, was filed on August 31, 2007, *see* Order No. 30499, with rates effective January 1, 2008.

The Company performed an updated depreciation study ("Depreciation Study") and requests authorization to implement the depreciation rates set forth in the Exhibit No. 3 of its

Application. The Depreciation Study identifies changes that have occurred since the Company's last depreciation study, measured the effect of the changes on the prudent recovery of presently surviving capital, and proposes revisions to the depreciation rates. The results of the Depreciation Study suggest an increase in annual depreciation expense of approximately $83.9 million ($160.8 million including the accelerated depreciation associated with early retirement of the Carbon plant) on a total Company basis, based on projected plant balances as of December 31, 2013.

RMP states that its proposed changes would result in an estimated increase to the Idaho jurisdictional depreciation expense of approximately $4.5 million ($8.9 million including the early retirement of the Carbon plant) beginning January 1, 2014.

RMP remarked that in order to maintain consistent depreciation rates across its six jurisdictions/service territories, the Company filed the Depreciation Study in Oregon, Utah, Wyoming, and Washington. In support of its Application, the Company attached the direct testimony of Henry E. Lay, Corporate Controller of PacifiCorp, John J. Spanos, Senior Vice President of Gannett Fleming, Inc., and K. Ian Andrews, Manager of Resource Development for PacifiCorp.

THE STIPULATION

The Parties engaged in a collaborative process, including a public workshop and subsequent correspondence, and eventually reached agreement on the aforementioned Stipulation that purports to settle the issues involved in this case. The following is a summary of the main terms of the Parties' Stipulation:

1. The Stipulating Parties agree that the proposed depreciation rates set forth in Attachment 1, Stipulated Rates, attached and incorporated into the Stipulation, represent just and reasonable depreciation rates for Rocky Mountain Power in Idaho commencing January 1, 2014.

2. The depreciation rates, originally proposed by the Company in its January 22, 2013, filing, result in an estimated increase in annual depreciation expense across PacifiCorp's six jurisdictions of approximately $160.8 million ($83.9 million excluding the early retirement of the Carbon Plant), based on estimated plant balances as of December 31, 2013, before the additional Oregon depreciation expense for shorter coal plant lives. Table 1 (see document) of the Stipulation shows the estimated impact of the agreed-upon changes to the depreciation rates on the Company's filed depreciation study. In Attachment 2 – Jurisdictional Allocation, detailed jurisdictional allocations are provided by category. As a result of the

settlement discussions, the Stipulating Parties have agreed to the following adjustments to the Company's filed depreciation study and proposed rates, as described in Paragraphs 9-29. These adjustments are summarized in Table 2 of the Stipulation (see document) and indicate the estimated impact on depreciation expense.

3. The Stipulating Parties have agreed to extend the terminal life estimate for the Gadsby Plant from December 31, 2022, to December 31, 2032. This adjustment results in new lower depreciation rates, including the impact of adding estimated interim retirements for the extended period. The stipulated depreciation rates also include recognition of the excess reserve adjustment in the calculation. The stipulated depreciation rates have been computed using an estimated terminal removal rate of $40/kW. (Adjustment A)

4. The Stipulating Parties have agreed to shorten the terminal life on the James River Plant from December 31, 2016, to December 31, 2015, to correct an error in the original Application, and to reduce net salvage estimated in the calculation from -1% to zero. These changes result in higher depreciation rates. (Adjustment B)

5. The Stipulating Parties agree that, for the Chehalis Plant, Currant Creek Plant, Lake Side Plant, Hermiston Plant and Gadsby Peaker Plant (Units 4-6), the interim retirement curve for Account 343 Prime Movers is changed from a 40-R_1 to a 45-$R_{2.5}$. There is no change in the proposed terminal removal dates for each of these plants from those presented in the study. The Stipulating Parties agree to lower the terminal removal cost for the CCCT gas units from the Company's proposed level of $20/kW to $15/kW. (Adjustment C)

6. The Stipulating Parties agree that wind generation units will use a 30-year terminal life. The terminal removal cost has been lowered from the Company's proposed level of $9/kW to $7/kW. (Adjustment D)

7. The Stipulating Parties agree that the Carbon Plant terminal net salvage estimate is reduced from the proposed $330/kW to $117/kW and the stipulated depreciation rates are calculated based on the April 2015 retirement date. This terminal net salvage estimate of $117/kW is used for calculating rates in this Stipulation and will not be relied on in developing future removal cost estimates for other generation facilities. Until actual results are available, updated current estimates will be provided as needed in future filings, and to the extent the updated estimates differ from the $117/kW, this issue can be reexamined in those filings. The amount ultimately deferred for the Carbon Plant will be trued up to actual prudently incurred removal costs in accordance with the procedures set forth in the stipulation in Case No. PAC-E-13-04 (the "GRC Stipulation").

The remaining plant balances for Carbon Plant will be recovered through 2020 consistent with the GRC Stipulation. (Adjustment E)

8. The Stipulating Parties accept the Company's proposed method in the study to use Iowa Curves to determine interim retirements for production facilities with terminal lives. The proposed depreciation rates reflect adjustments to the retirement curves on coal generation facilities in Account 311 Structures and Improvements from 90-R_2 to 120-$R_{1.5}$, Account 312 Boiler Plant Equipment from 60-L_1 to 68-S_0 and Account 314 Turbo-generator Units from 55-L_1 to 57-S_0. Reliance on the Company's Iowa Curve method for settlement purposes shall not prevent parties from taking a different position on this issue in future depreciation cases. (Adjustment F)

9. The Stipulating Parties agree to extend lives on transmission assets by: (1) extending the curve for Account 353 Station Equipment from the proposed 57-S_0 to a 58-S_0, (2) extending the curve for Account 356 Overhead Conductors and Devices from 60-R_3 to 63-R_3; and (3) merging Account 353.7 Supervisory Equipment with Account 353 Station Equipment resulting in a change to the life-curve combination and related net salvage for those assets from the proposed 20-R_2 with zero net salvage to 58-S_0 with -5% net salvage. All other lives and retirement curves are accepted as proposed by the Company. Any transmission excess reserve balance will be amortized over the remaining life of the assets rather than on an expedited basis. As part of calculating the stipulated depreciation rates, the depreciation reserve has been redistributed within the transmission function resulting in reduced rates on all accounts within the transmission function and an overall reduction in the composite depreciation rates on those facilities. (Adjustment G)

10. The Stipulating Parties agree to extend lives on distribution assets by merging Account 362.7 Supervisory Equipment with Account 362 Substation Equipment, and using the appropriate state-specific lives for Account 362 in Utah, Idaho and Wyoming. (Adjustment H)

11. The Stipulating Parties agree to amortize net salvage on specific mining accounts as follows: (1) stipulated depreciation rates for Utah mining assets have been established using a terminal life as established in the filed study; (2) net salvage percentages have been adjusted for Account 399.41 Surface Processing Equipment – Preparation Plant from -7% to -6% and for Account 399.46 Longwall Equipment from 5% to 7%; and (3) depreciation reserves have been reallocated within the mining accounts. As a result, the stipulated depreciation rates are lower than the Company's proposed rates on most of the mining accounts. (Adjustment I)

12. In order to offset the depreciation expense impacts of the shortened remaining life at the Carbon Plant, which is calculated to be $34.7 million, the Stipulating Parties agree to expedite the amortization of the excess depreciation reserve at the Gadsby Plant and the Hunter Plant. The Stipulating Parties agree that the excess reserve at the Gadsby Plant and the Hunter Plant, calculated as of December 31, 2011, will be returned on a straight line basis. The excess reserve of $21,073,503 associated with the Gadsby Plant will be amortized based on 9 years and the excess reserve of $29,635,920 associated with the Hunter Plant will be amortized based on 5 years, resulting in an annual amortization of $8.2 million. These amounts will be recorded as a separate item by crediting depreciation expense and debiting the depreciation reserve. The new depreciation rates for the Hunter Plant and Gadsby Plant have been recomputed excluding the above identified amounts of excess reserve. This recalculation of rates produced an estimated increase in depreciation expense of $2.4 million. Coupled with the $8.2 million excess reserve amount, this results in a net annual decrease in depreciation expense of $5.8 million. The Stipulating Parties agree the excess reserve amortization will occur annually starting January 1, 2014, and will continue until the full $34.7 million is returned or ending with the implementation of new rates resulting when new rates from the next depreciation study are implemented. During the next depreciation case, an assessment will be made as to the final disposition of any remaining amount of the $34.7 million which has not been returned at that time. (Adjustment J)

13. The Stipulating Parties agree to amortize depreciation excess reserve for two other steam generation plants with an excess reserve as of December 31, 2011, the Blundell Plant with an excess reserve of $7,852,016 and the Colstrip Plant with an excess reserve of $22,930,383, as follows: (1) the annual amount is determined for each plant with any excess reserve by dividing the excess reserve by 10; (2) the annual amortization will occur beginning January 1, 2014, until new depreciation rates resulting from the next depreciation study are implemented; and (3) the stipulated depreciation rates are determined by excluding the identified excess reserve in the calculation. This adjustment is intended to offset the large steam plant increase in this Stipulation and does not set precedent for any future depreciation study. (Adjustment K)

14. The Stipulating Parties agree to amortize depreciation excess reserve on distribution plant for Utah, Idaho and Wyoming as follows: the annual amortization has been determined for each state by identifying the excess reserve for each state individually in the Company's filed study as of December 31, 2011, and then dividing the excess reserve for Utah by 6.5 years, the excess reserve for Idaho by 13 years, and the excess reserve for Wyoming by 15 years. The stipulated depreciation rates have been determined by excluding the identified excess reserve amounts from the

calculation. The annual amortization will occur beginning January 1, 2014, until new depreciation rates from the next depreciation study are implemented. This adjustment is intended to offset the large steam plant increase in this Stipulation and does not set precedent for any future depreciation study. (Adjustment L)

15. The Stipulating Parties agree to stipulated depreciation rates calculated using June 30, 2013, actual account balances within specific functions without terminal lives, including transmission, Utah, Idaho and Wyoming distribution and Utah, Idaho and Wyoming general plant. (Adjustment M)

16. The Stipulating Parties agree to adjust general plant lives to be consistent with the Oregon Settlement. Utah, Idaho and Wyoming depreciation rates have been adjusted using the life-curve combinations agreed to in Oregon. For Idaho, Account 390 Structures and Improvements, the life has been changed from $55R_3$ to $58\text{-}R_1$, Account 392.09 Transportation Equipment-Trailers from $33\text{-}L_2$ to $34\text{-}L_2$ and Account 396.03 Light Power Operated Equipment from $8\text{-}R_2$ to $9\text{-}L_3$. Each state's estimated salvage remains as provided in the Company's originally filed depreciation study. (Adjustment N)

17. For the depreciation rates for Wyoming and Idaho, the Stipulating Parties agree to adjust Klamath-Accelerated depreciation to an end date of December 31, 2022, consistent with the approved life in Utah. The life may be reassessed in the next depreciation cases in Wyoming and Idaho. If Klamath-Accelerated facilities are retired prior to December 31, 2022, return of and on any remaining balance will continue after retirement of the facilities as though it remained in service through December 31, 2022, and the Stipulating Parties agree not to challenge this recovery based on "used and useful" arguments. (Adjustment O)

18. The Stipulating Parties agree to the Company's proposal to move the balance of communication equipment to mass asset accounting with a consistent 24-year life and a depreciation rate of 4.3%. The depreciation reserves will continue to be maintained on a state basis which ensures no inadvertent jurisdictional transfer of depreciation reserve benefits created from different depreciation rates historically being used by each state.

19. The Stipulating Parties agree that the Company will provide a section in the next depreciation study, for informational purposes only, listing the specific mining assets, reserve balances, and respective lives owned by its Wyoming mining subsidiary.

20. A new depreciation study will be filed with the Idaho Public Utilities Commission no later than five years from the date of the written order resolving the issues in this Docket, or as otherwise ordered by the

Commission. The Stipulating Parties agree the Company will maintain the right to file a new depreciation study sooner than five years.

21. The Stipulating Parties agree the Company will implement a reporting system to keep the Stipulating Parties and the Utah, Idaho and Wyoming Commissions informed regarding any matters likely to have implications regarding potential stranded costs of generating assets. The Company will propose a reporting method by no later than December 31, 2013.

22. The Stipulating Parties agree the Company will provide updated cost estimates regarding Carbon Plant's terminal net salvage, including any new third-party studies as part of the Company's next general rate cases in Idaho, Utah and Wyoming.

23. The Stipulating Parties agree to adhere to the depreciation study treatment established according to paragraphs 10-14 of the Stipulation in Case PAC-E-13-04 (the "GRC Stipulation") if approved by the Idaho Public Utilities Commission. The parties are requesting that the stipulated depreciation rates from this study be effective on January 1, 2014 for purposes of financial reporting. Per the GRC Stipulation, the Company will establish a regulatory asset that will track for further recovery or refund, the aggregate net difference between the depreciation expense that would have been booked beginning in 2014 under the depreciation rates in effect as of the date of the GRC Stipulation and the depreciation expense actually booked beginning in 2014 under the depreciation rates approved by the Commission in this Case until the new depreciation rates are reflected in customer rates. Recovery of the deferral shall be allocated to customers on a proportionate basis, based on the cost of service relationships established in the next Idaho general rate case with rates proposed to be effective on or after January 1, 2016, as modified by future cost of service studies in future rate cases.

STAFF COMMENTS

Staff participated in the discussions, reviewed and analyzed the adjustments as presented and agreed upon in the Stipulation. A complete table of the proposed adjustments is included in Table 2, page 5, of the Stipulation. However, Staff singled-out the following items for further explanation:

Adjustments J and K relate to excess reserves in the steam production plants. The issue evaluates whether the steam production plant should be considered as one category (function) rather than as individual plants for depreciation purposes. When reviewed on an individual basis, some plants appear to have depreciation reserve deficits and some appear to have depreciation surpluses. This is caused by timing differences due to changes in depreciation factors during the life of the assets. However, if you combine all plants into one function group, offsetting the surpluses and deficits, it reduces the depreciation expense currently required. PacifiCorp assured Staff that it had discussed this practice with the Company's Generally Accepted Accounting Principles (GAAP) advisors and were advised that it did not violate GAAP.

Staff looked at the Uniform System of Accounts (USOA) 108c, other states' reserve practices, and accounting publications to determine if combining reserves for depreciation purposes was an acceptable practice. Based on Staff findings and the fact that it is a timing difference which will correct itself in the near future, Staff accepted the Adjustments J and K as being a fair compromise of the Parties. <u>These two adjustments account for a reduction in Idaho depreciation expense of approximately $432,000</u>.

Adjustment E adjusts for a reduction in estimated Carbon Plant costs. Originally, the Company estimated a Carbon Plant removal cost of $330/kW. Existing depreciation rates include $40/kW for removal costs. Based on Staff's calculations, the $117/kW removal cost appears to be a fair compromise of the Parties. This amount will be re-examined as estimates are updated and will be trued up to actual prudently incurred removal costs in accordance with the procedures set forth in the Stipulation in Case No. PAC-E-13-04 (the "GRC Stipulation"). Staff agrees with this adjustment as a fair and reasonable compromise by the Parties. <u>This adjustment reduces Idaho depreciation expense by approximately $1.5 million</u>.

Adjustment L deals again with the issue of surplus and deficit reserves, as discussed earlier regarding Adjustments J and K, only Adjustment L relates to Distribution Plant for Idaho. Staff accepts this adjustment as being a fair compromise of the Parties. <u>This adjustment reduces Idaho depreciation expense by approximately $1.1 million</u>.

The Company's initial Application requested $8,851,848 as Idaho's allocated share of depreciation expense. *See* Staff Comments, Table 1, page 3. In the Stipulation, the Parties agree that Idaho's allocated share would be $4,614,970, a difference of -$4,236,878. *Id.*

Staff believes that the Stipulation is a fair, just and reasonable compromise of the issues. Staff issued a caution regarding the limitation of depreciation expense for current customers. Staff warns that the Commission must take care so as not to unfairly defer depreciation expense to future customers. Staff recommended the Commission approve the Stipulation and all of its terms and conditions.

COMMISSION FINDINGS

The Commission reviewed the record in this case, including RMP's Application, the Stipulation, and Staff comments.[1] The Commission is satisfied that the major stakeholders in this case reached an amicable settlement regarding proposed changes to depreciation rates applicable to RMP's depreciable electric plant. Accordingly, the Commission accepts the Parties' Stipulation as filed.

The Commission affirms the Parties' negotiated agreement to include slightly more than half of the depreciation expense originally proposed in RMP's Application. Specifically, the agreed-upon adjustment of reserve amounts and carbon removal costs moving forward directly impacts Idaho customers. The Commission finds that the Parties' decision to adjust excess or surplus plant reserves and increase the $/kW cost of carbon removal above the existing cost are reasonable and appropriate.

The Commission believes that Idaho's allocated share of RMP's depreciation expense included in the Stipulation strikes a fair and reasonable balance between the inclusion of existing depreciation expense in rates beginning on January 1, 2014, and the deferral of a portion of depreciation expense to future customers. The stipulated rates, attached and incorporated into the Stipulation, are fair, just and reasonable depreciation rates for RMP customers in Idaho beginning January 1, 2014.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over PacifiCorp dba Rocky Mountain Power, an electric utility, and the Application in Case No. PAC-E-13-02 pursuant to Title 61, Idaho Code, and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq.*

O R D E R

IT IS HEREBY ORDERED that the Parties' Stipulation pertaining to PacifiCorp dba Rocky Mountain Power's Application for approval of proposed changes to depreciation rates applicable to the Company's depreciable electric plant is approved. The depreciation rates set forth in Attachment 1 to the Stipulation shall be effective as of January 1, 2014.

[1] The Commission notes that the Company's last request for approval of changes to its depreciation rates was filed in 2007, with a January 1, 2008 effective date, PAC-E-07-14 (Order No. 30499).

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 18th day of November 2013.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Mack A. Redford

MACK A. REDFORD, COMMISSIONER

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

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