118 FERC ¶ 63,009
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Chehalis Power Generating, L.P. Docket No. ER05-1056-002

INITIAL DECISION

(Issued January 16, 2007)

APPEARANCES

*Neal L. Levy, Esq., Bruce L. Richardson, Esq., Patrick E. Groomes, Esq. and T. Raymond Cunningham, Esq.* on behalf of Chehalis Power Generating, L.P.

*John Lilyestrom, Esq., Eric H. Carter, Esq. and Shannon Torgerson, Esq.* on behalf of Bonneville Power Administration

*Diane Schratwieser, Esq. and James Pepper, Esq.* on behalf of Federal Energy Regulatory Commission

HERBERT GROSSMAN, Presiding Administrative Law Judge

1. At issue in this proceeding is whether Chehalis Power Generating, L.P.'s (Chehalis) proposed Rate Schedule FERC No. 2 (Rate Schedule or Schedule 2) for providing Reactive Supply and Voltage Control from Generation Sources Service (reactive service) for its electric power generating facility interconnected to the transmission system of the Bonneville Power Administration (BPA), for the locked-in period of August 1, 2005 through September 30, 2006, complies with the terms of the TransAlta Settlement Agreement (TransAlta Settlement or Settlement Agreement). The proposed Rate Schedule includes both a Fixed Capability Component and Heating Losses Component.

## I. PROCEDURAL HISTORY AND BACKGROUND

2. Pursuant to Section 205 of the Federal Power Act, on May 31, 2005, Chehalis[1] filed a proposed rate schedule that contains a formula to calculate its revenue requirement for supplying reactive power to BPA from Chehalis' electric generating facility (Facility), a 520 MW power plant, consisting of two natural gas generators and one steam generator, located in Chehalis, Washington. *Chehalis Power Generating, L.P.*, 112 FERC ¶ 61,144 at P 2 (2005) (July 2005 Order). Chehalis' proposed rate schedule sets forth its revenue requirement for providing reactive power to BPA based upon three components: 1) a Fixed Capability Component which is designed to recover the portion of plant costs attributable to the reactive power capability of the Facility; 2) a Heating Losses Component which is designed to recover the value of real power lost as a result of the production of reactive power; and 3) a Service Factor which is a mechanism resulting from the Settlement Agreement between Chehalis and BPA that is intended to represent the operational status of the Facility. July 2005 Order at ¶ 8.

3. Chehalis' filing was made pursuant to the TransAlta Settlement, approved in Docket No. ER04-810-000.[2] *TransAlta Centralia Generation, L.L.C.*, 111 FERC ¶ 61,087 (2005)(*TransAlta*). The TransAlta Settlement resolved all issues relating to a Reactive Power Service rate filing seeking compensation from BPA for reactive support provided to it by the Centralia Steam Electric Generating Plant owned by TransAlta.[3] The TransAlta Settlement also specified procedures for the filing of Reactive Power Service rates by each of the generator settling parties. Under the terms of the TransAlta Settlement, each generator's reactive power rate shall be determined pursuant to the rate methodology established by the Commission in *American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd* 88 FERC ¶ 61,141 (1999)(*AEP* or Opinion No. 440*); approved, WPS Westwood Generation, L.L.C.*, 101 FERC ¶ 61,290 (2002)(*WPS Westwood*), as it existed on the date the TransAlta Settlement was filed, February 16, 2005, regardless of subsequent modifications to the methodology or new methodologies adopted by the Commission (the Current *AEP* Methodology).

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[1] Chehalis is an exempt wholesale generator under section 32 of the Public Utility Holding Company Act of 1935. *See Chehalis Power Generation L.P.*, 96 FERC ¶ 62,204 (2001). It is authorized to make wholesale sales of power at market-based rates. *See Chehalis Power Generation L.P.*, Docket No. ER03-717-000 (May 9, 2003) (unpublished letter order).

[2] The Settlement Agreement is between BPA, Chehalis, TransAlta Centralia Generation, L.L.C. (TransAlta), Calpine Corporation (Calpine), and its subsidiaries, Goldendale Energy Center, LLC (Goldendale) and Hermiston Power Partnership (Hermiston).

[3] The Commission approved the TransAlta Settlement by letter order issued April 19, 2005 in Docket No. ER04-810-000.

4. BPA filed a timely motion to intervene and protest. BPA agreed in the TransAlta Settlement not to challenge rates based upon the Current *AEP* Methodology; however, BPA reserved the right to challenge rates that are not based on the Current *AEP* Methodology. July 2005 Order at P 14.

5. On July 27, 2005 the Commission accepted Chehalis' proposed rate schedule for supplying reactive power to BPA, and suspended it for a nominal period, to become effective August 1, 2005, subject to refund. July 2005 Order at ¶ 1. In its July 2005 Order, the Commission also established hearing and settlement judge procedures. *Id.* On August 3, 2005, the Chief Judge issued an order designating Judge H. Peter Young as Settlement Judge. Following unsuccessful settlement discussions, on January 19, 2006, the Chief Judge terminated the settlement proceeding and designated me as the Presiding Judge.

6. On August 26, 2005, Chehalis filed a request for rehearing of the July 2005 Order. The Commission denied Chehalis' request for rehearing on December 15, 2005. *Chehalis Power Generating, L.P.,* 113 FERC ¶ 61,259 (2005).

7. The hearing commenced on September 26, 2006, and concluded on October 5, 2006.

## II. ISSUES

8. On August 11, 2006, the parties submitted a Joint Statement of Issues, stating the issues to be adjudicated as follows:

**Issue 1.** Does the Reactive Power Service rate submitted by Chehalis comply with the "Current *AEP* Methodology" as defined in the TransAlta Settlement in Docket No. ER04-810-000?

**Issue 2.** Is Chehalis' proposal to update its rate for reactive power service annually (other than for updates to the Service Factor) permitted under the TransAlta Settlement?

**Issue 3.** Is Chehalis' calculation of the Fixed Capability Component of its proposed Reactive Power Service rate consistent with the requirements of the TransAlta Settlement, and, if not, what Fixed Capability Component of the reactive service rate would be consistent with the TransAlta Settlement?

**Issue 4.** Is Chehalis' proposal to include a Heating Losses Component in Chehalis' reactive service rate permitted under the TransAlta Settlement?

**Issue 5:** Did Chehalis utilize the correct power factors for use in the reactive allocators in calculating its proposed Reactive Power Service rate?

**Issue 6.** Did Chehalis correctly determine Total Production Plant in calculating its proposed Reactive Power Service rate? In particular, did Chehalis correctly determine Total Production Plant with respect to:

a. the BPA 500 kV Switchyard?
b. the Transmission Line Capacity Reservation Fee?
c. the Natural Gas Interconnection and Metering cost?
d. the $900,000 payment to BPA at financial closing?
e. cost of installation?
f. the Interest During Construction?[4]

**Issue 7.** Did Chehalis correctly determine the total costs of Accessory Electric Equipment in calculating its proposed Reactive Power Service rate? In particular, did Chehalis correctly determine the total costs of Accessory Electric Equipment with respect to:

a. the BPA 500 kV Switchyard?
b. the Chehalis Substation?
c. the Weather Station?[5]
d. the Distributed Control System?[6]
e. the Isolated Phase Bus?[7]
f. cost of installation?

**Issue 8.** Did Chehalis correctly determine test year depreciation in calculating its proposed Reactive Power Service rate?[8]

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[4] Staff withdrew its opposition to Chehalis' inclusion of Interest During Construction; therefore, I find this is no longer an issue. *See* Tr. at 475:8-9.

[5] In its original filing, Chehalis included costs associated with it Weather Station in its Accessory Electric Equipment. Staff opposed this categorization. In his rebuttal testimony, Chehalis witness Honeycutt agreed to remove the weather station from Accessory Electric Equipment on the basis that it is included in FERC sub-account 316.9. *See* Ex. CPG-32 at 27:13-21. Therefore, I find this is no longer an issue.

[6] Chehalis and Staff agree that the Distributed Control System should be included in Chehalis' Accessory Electric Equipment Account. BPA did not take a position on this issue. *See* Ex. CPG-32 at 27:22-28:3. Therefore, I find this is no longer an issue.

[7] Staff and Chehalis agree that the Isolated Phase Bus is appropriately included in the Accessory Electric Equipment account. *See* Ex. CPG-32 at 28:4-10. Therefore, I find this is no longer an issue.

[8] Chehalis has agreed that the 2003 depreciation recognized in 2004 should be (footnote con't next page)

**Issue 9.** Did Chehalis correctly apply the requirements of the TransAlta Settlement with respect to the utilization of levelized or non-levelized rates, and, if not, what utilization is correct under the TransAlta Settlement?

a. If levelized rates are appropriate for Chehalis' proposed Reactive Power Service rate, what is the appropriate depreciation formula and composite income tax factor formula?

b. If a non-levelized rate is appropriate for Chehalis' proposed Reactive Power Service rate, it is correctly calculated?

**Issue 10.** Did Chehalis correctly calculate its cost of debt in its proposed Reactive Power Service rate?

**Issue 11.** If a Heating Losses Component is permitted under the TransAlta Settlement, has Chehalis properly calculated the Heating Losses Component of its proposed Reactive Power Service rate, and, if not, what Heating Losses Component is appropriate?

## III. STATEMENT AND DISCUSSION

### A. Annual Updates to Reactive Power Service

#### 1. Positions of the Parties

*Chehalis*

9. Unlike most reactive service filings, Chehalis states that its rate schedule is subject to the terms and conditions of the TransAlta Settlement. One such condition is that Chehalis' compensation for reactive power service must comply with the Current *AEP* Methodology as it existed on February 16, 2005. The second condition is the application of the Service Factor. Chehalis explains that the Service Factor converts the rate from one based on capability to one based on the actual operational history of the generating facility. Accordingly, Chehalis' claimed revenue requirement of $2,954,013.56 plus $500,662.71 is subject to a 63.1 percent Service Factor, rendering an annual amount of $2,179,900.73. *See* Ex. No. CPG-63 at 9. The third condition that Chehalis highlights is

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removed from its proposed Reactive Power Service rate. Ex. CPG-32 at 29:5-8. Accordingly, this is no longer an issue. Chehalis I.B. at 42-43; BPA I.B. at 29; Staff I.B. at 42.

that departures from the TransAlta Settlement are subject to a public interest standard.[9] Chehalis I.B. at 7-9.

10. Chehalis argues that, with the adjustments reflected in Exhibit No. CPG-63, its Reactive Power Service rate complies with the Current *AEP* Methodology. *Id.* at 9.

11. Chehalis contends that its proposal to update components of its annual Reactive Service rate, in addition to the Service Factor, is permitted under the TransAlta Settlement. Chehalis maintains that the plain language of the TransAlta Settlement, together with principles of contract construction, supports its interpretation. *Id.* at 11. Section D.15 of the TransAlta Settlement states, "[t]he purpose of the submission is to notify the Commission of the adjustment to the *Service Factor element in the formula rate* established by this Settlement Agreement." Ex. CPG-3 at 19 (emphasis added). According to Chehalis, the words "formula rate" should be read in the context of the Service Factor as being just one element of a larger formula rate. Chehalis identifies that larger formula as the Current *AEP* Methodology. Chehalis argues that the implementation of the Current *AEP* Methodology is the filing of a rate schedule setting forth the annual rates for reactive service, together with the "Schedules" referenced in witness Ralph Honeycutt's testimony.[10] *See* Ex. Nos. CPG-1 and CPG-32. These Schedules provide the formulas that are used with test year data to update the rate. According to Chehalis, so long as it does not change the formulas in its Schedules, it is in compliance with the TransAlta Settlement. Chehalis I.B. at 11-15.

12. Chehalis argues that other provisions of the TransAlta Settlement also support its position. Chehalis maintains that Section B, which states that no Settling Party may seek to change the Settlement during its effective term, does not contradict Chehalis' proposed use of a formula rate. Further, Chehalis contends that Section B does not preclude filings that are in compliance with the TransAlta Settlement. Under Section C.5, specific rate components such as return on equity and capital structure cannot be changed; however Chehalis contends that it is permitted to update the remaining components of its Filed Rate. Chehalis also draws attention to the specific terminology used in subsections (b) and (c). Subsection (b) contains the term "Reactive Power Service rate," which Chehalis interprets as the term used to define Chehalis' rate in its initial filing. In contrast, in subsection (c), Chehalis claims that the term "annual," as stated in the phrase "annual rate determined by the Current *AEP* Methodology" coincides with the annual rate included in Chehalis' Rate Schedule. According to Chehalis, the terms have different meanings. *Id.* at 15. Chehalis also mentions that provision D.14, which references both the Service

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[9] *See United Gas Co. v. Mobile Gas Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

[10] Examples of Chehalis' Schedules are Exhibit Nos. CPG-4, CPG-8, CPG-9, CPG-10, CPG-11, CPG-13, CPG-14, CPG-16 and CPG-63.

Factor element of the formula rate and the updated rate itself, and uses the term "annual rate determined by the Current *AEP* Methodology" does not include a limitation that would preclude the application of a formula rate. *Id.* at 16.

*Bonneville Power Administration*

13. BPA argues that the Reactive Power Service rate submitted by Chehalis does not comply with the Current *AEP* Methodology as defined in the TransAlta Settlement. According to BPA, Chehalis failed to apply the requirements of the methodology followed in *AEP* to its entire rate calculation. BPA asserts that Chehalis' deviation from the *AEP* method is contrary to the Commission's effort, as articulated in *WPS Westwood,* to create a standardized method "of how charges for reactive power generation should be determined." BPA I.B. at 5-6, *citing WPS Westwood* at P 14.

14. With the exception of the Service Factor, BPA argues that Chehalis is not permitted to update elements of its rate. BPA maintains that Section B of the TransAlta Settlement does not provide for filing or any other updates to the revenue requirement apart from: (i) an initial Federal Power Act § 205 rate filing, (ii) a subsequent rate filing to change the rate on or after October 1, 2007, or (iii) the annual Service Factor updates. BPA. I.B. at 7. Further, BPA states that the remaining sections that Chehalis relies on for support do not authorize other compliance filings, but instead relate to the Service Factor.[11] In addition, BPA rejects Chehalis' contention that the phrase "new reactive power rate" provides support for Chehalis' position. Instead, BPA asserts the referenced "new" rate is the existing revenue requirement as multiplied by the updated Service Factor. *Id.* at 10.

15. Except for the Service Factor, BPA argues that the settling parties did not intend to permit cost updates. BPA states that it is implausible that the settling parties, with the purpose of resolving issues related to current and future Reactive Power Service rate filings, would have contemplated additional revisions, but remained silent. *Id.* Further, BPA argues that the settling parties' intention is demonstrated by the fact that no other party to the TransAlta Settlement has made a filing to update any element of its Reactive Power Service rate, other than the Service Factor. BPA asserts that the settling parties' intention is verified by the fact that Chehalis is not required to provide BPA with the necessary back-up data for Chehalis' "updates." BPA explains that this is inconsistent with Chehalis' requirement to submit supporting data to permit BPA to certify the

[11] Section C.5 authorizes annual revisions to the Service Factor; Sections D.14 and D.15 outline the procedures for revising the Service Factor; Section D.14 also provides the input for the Service Factor calculation; and finally, Section D.15 states that the revised Reactive Power Service rate results from changes to the Service Factor only. BPA I.B. at 8-10.

updated Service Factor calculation. *Id.* at 11-12. Finally, BPA mentions that, because Chehalis is exempt from the Commission's uniform system of accounts, no mechanism exists to audit unapproved changes that affect inputs to the Reactive Power Service rate calculations. *Id.* at 12.

*Commission Trial Staff*

16. It is Commission Trial Staff's (Staff) position that Chehalis' proposed Reactive Power Service rate does not comply with the Current *AEP* Methodology as defined in the TransAlta Settlement. Staff asserts that the only part of Chehalis' proposed reactive power rate that complies with the TransAlta Settlement is the Service Factor. Staff I.B. at 11-12.

17. Staff argues that Chehalis' claim that it is entitled "update" the individual components of the Fixed Capability Component should be rejected for three reasons. First, there is no such entitled provided in the TransAlta Settlement. Second, the TransAlta Settlement does not provide Chehalis the right to update the components of its reactive power rate other than the Service Factor, prior to October 1, 2007. Third, Staff alleges that Chehalis' proposed formula is a stated rate, and does not conform to the characteristics typical of a formula rate ordinarily filed with the Commission. *Id.* at 14-21.

**2. Discussion**

18. At the outset, one issue or non-issue, as the case may be, concerns Chehalis' position that it may update annually all of its inputs into the reactive service rate. Throughout the hearing, Chehalis took the position that this is not really an issue to be decided in this proceeding and only becomes an issue in its attempted filing of an update, which is not part of this docket unless ordered otherwise in the future by the Commission. Technically, it may be correct. But, in light of this issue's possible impact on the levelized vs. non-levelized issue (if no update were permitted for other than the Service Factor, the non-levelized methodology would lock in the starting depreciation basis for the whole locked-in period, at seeming variance with that methodology's assumption of continual reduction in net plant), and also as a starting point for the Commission, if it wishes to decide the issue, I will make my determination.

19. For the most part, the wording in the TransAlta Settlement is straightforward and would appear to prohibit any change to the initial reactive power rate before October 1, 2007, other than the annual adjustment to the Service Factor.

20. Section B permits only three types of filings prior to October 1, 2007: (1) an initial Federal Power Act § 205 filing; (2) a subsequent rate filing to change the rate that would

be effective on or after October 1, 2007; and, (3) filings with the annual Service Factor update. Ex. CPG-3 at 3-4.

21. Section D.14 of the agreement then explains how the Service Factor is to be calculated (basically on the proportion of time during the preceding three years that the generating plant was operating while connected to the system), to be applied against the annual rate determined under the *AEP* methodology, for the initial and updated periods. *Id.* at 17-18.

22. Section D.15 requires the plant owner to provide BPA with the new reactive power rate based on the updated Service Factor, with all supporting data, by August 15 of each year, for transmittal to Commission as a compliance filing under the Settlement Agreement. *Id. at* 19. And, in seeming consistency with this scheme of permitting and requiring an annual change only to the Service Factor, Section D.15 goes on to state that "*the* purpose of the submission is to notify the Commission of the adjustment to the Service Factor element in the formula rate established by this Settlement Agreement." *Id.*, emphasis supplied.

23. Chehalis, however, seizes on the words "formula rate" in this sentence to suggest otherwise. If a formula rate, as that term is generally utilized in FERC terminology, were established by the Settlement Agreement, it would require periodic updates to all elements of the calculation, not merely the Service Factor.

24. But as Staff points out, none of the attributes of a traditional formula rate are provided under the Settlement Agreement. There are no provisions for particular inputs, terms or conditions, as a formula rate would require. *See* Staff I.B. at 15-18. Moreover, if updates other than to the Service Factor were permitted, this would undermine the entire substance of the Settlement Agreement's limitations with regard to other filings during the period before October 1, 2007. And it would directly contradict the sentence relied upon by Chehalis that contained the words "formula rate," which gave, as the purpose for the updated filing, the adjustment of the Service Factor.

25. Clearly, "formula rate" in the Settlement Agreement is not the term of art usually referred to in FERC parlance. It appears to be merely a logical reference to the simple formula construct of the Settlement Agreement itself, whereby the *AEP* calculation is multiplied by the Service Factor to produce the Schedule 2 amount to be passed on to transmission customers. It is simply: A x B = C; i.e., the result of applying the *AEP* methodology, times the updated Service Factor, to equal the Schedule 2 amount. Only under this reading are there no contradictions in the language of the Settlement Agreement. Consequently, in accordance with the apparent purpose of the Settlement Agreement and its consistent language, Chehalis may adjust only the Service Factor in its annual update and may make no other filings that would otherwise change its rate from its initial one, until it files for a change that would take effect on or after October 1, 2007.

26. This reading of the language of the Settlement Agreement does not necessarily or conclusively foreclose an updating of purely mathematical calculations for which the inputs have already been established in the initial filing, as for example, to net plant under a non-levelized methodology. In that a calculation must be made in successive annual periods using the new Service Factor, an argument can be made that, since the amount of reduction to net plant can be precisely determined mathematically without further inputs still to be determined, an updated filing which does not make that reduction would necessarily be in error. This might especially be the case here, where the reactive power reimbursement on Schedule 2 is Chehalis' only rate, and no offsetting adjustments to other rates are possible to neutralize or compensate for the overrecovery attributable to not reducing net plant, as in the case of the traditional utility whose other rates are also regulated. But, even though it is obvious that none of the parties to the Settlement Agreement other than Chehalis considered the utilization of a non-levelized methodology, in the absence of a either a specific provision in the Settlement Agreement or a determination by the Commission to do so based upon policy considerations, permitting even an update of a purely mathematical item would appear to be overreaching.

## B. Calculating the Fixed Capability Component Allocator of the Reactive Power Rate

### 1. Positions of the Parties

*Chehalis*

27. The Fixed Capability Component of the revenue requirement represents the portion of the plant investment in the Chehalis facility that can be attributed to the production of reactive power. Chehalis calculated this component by analyzing the reactive portion the facility's generator/excitation system and the GSU investment. Ex. CPG-1 at 11. Chehalis argues that its calculation of $2,954,013.56 Annual Revenue Requirement for Investment on Reactive Power Capability is consistent with the TransAlta Settlement. Chehalis explains that the $2,954,013.56 includes a $3,597.31 reduction from the $2,957,610.87 calculation initially presented. *See* Ex. CPG-13 at 1:13 and Ex. CPG-1 at 11:13 to 26:6.

28. Chehalis explains that an allocator is necessary to determine the portion of generator/exciter investment that is properly assigned to the production of reactive power. In developing its reactive power allocator, Chehalis claims that it has correctly employed the following approach upheld by the Commission in *AEP*: "the allocation factor should be based on the capability of the generators to produce VARs and this capability should be measured at the generator terminals." Chehalis I.B. at 27, *quoting AEP* at 61, 457.

29. In order to determine the allocation factor, Chehalis states that it is necessary to know three items: (i) the real power capability of the turbines, or MW, (ii) the reactive power capability of the generators, or MVAR, and (iii) the apparent power capability of the generators, or MVA. *Id.* at 27-29. Chehalis determined that the real power capability of the turbines by using the nameplate data for each of the combustion turbine generators and then applied a correction factor to account for things such as air pressure, temperature, and humidity can impact the real power output of a turbine. The reactive power capability of the generators or MVAR are determined by capability curves unique to the particular generator design. *Id.* at 29. Finally, the MVA is calculated by applying the MW and MVAR ratings in the MVA Equation for each combustion turbine generator and steam turbine generator. *See* Ex. CPG-32. Using the MVAR and MVA values reflected in Exhibit No. CPG-12 at 1 and Exhibit No. CPG-63 at 8,[12] Mr. Honeycutt calculated the Reactive Power Allocation Factor (RPAF) (also referred to as the reactive allocator) for the Chehalis facility as follows:

$$\text{RPAF} = \frac{MVAR_{Facility}{}^2}{MVA_{Facility}{}^2} = \frac{413.4\,MVAR^2}{664.3\,MVA^2} = 0.3873 \text{ or } 38.7\%$$

Ex. CPG-32 at 18:17-20.

*Bonneville Power Administration*

30. BPA argues that Chehalis' calculated Fixed Capability Component is not consistent with the Settlement Agreement, and further, that Chehalis has not justified a Fixed Capability Component of more than $973,163.85 per year (after application of the Service Factor). BPA I.B. at 13; *see* Ex. BPA-11 at 40:7-11.

31. BPA argues that Chehalis' departure from using the nameplate capability of the generator deviates from the Current *AEP* Methodology and is inconsistent with other Commission approved reactive rates. BPA alleges that Chehalis manipulated the formula to produce a lower power factor, and higher reactive allocator, by claiming an artificially low real power rating for its generators. BPA I.B. at 16-17. In calculating its proposed 38.7 percent reactive power allocator, Chehalis uses a 0.78 power factor for its two combustion turbine generators, despite equipment limitations identified in Chehalis' filing indicating that the project's generators cannot operate at a 0.78 power factor. Chehalis' rated power factor results in a reactive allocator suggesting that approximately 60 percent of the relevant generator costs are for real power. BPA suggests that this result is not reasonable, and inconsistent with earlier Commission determinations that generating units are primarily in place for the purpose of generating real power. Instead,

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**12** The total reactive output for the generating facility is 413.4 MVAR (140 + 140 + 133.4) and the total apparent power output is 664.3 MVA (221.8 + 221.8 + 220.8).

BPA suggests that the three generating units' rated 0.85 power factor should be used, which results in a 27.75 percent reactive power allocator. *Id.* at 17-23.

*Commission Trial Staff*

32. Staff argues that Chehalis improperly calculated the Fixed Capability Component of its Reactive Power Service rate. The correct Fixed Capability Component should be $468,626.64. Staff I.B. at 21-22.

33. Staff argues that Chehalis did not use the correct power factors in calculating its Reactive Power Service rate. Staff alleges that Chehalis mixed nameplate MVAR rating with selective test-result-based MW capabilities to develop its reactive power allocator. *Id.* at 26. Pursuant to the Current *AEP* Methodology and good engineering practice, Staff submits that the reactive power allocator should be based on nameplate MW and MVAR ratings, not on a mixture of values derived from test data. *Id.* at 27. Staff asserts "[i]t is important to determine the MVAR rating of a generator at the same time that the MW rating is determined because they are interrelated" and Chehalis ignored this interrelation in its calculations. *Id.* at 26; Ex. S-9 at 13:1-3.

34. Staff suggests a formula based on a 0.85 power factor to derive a reactive allocator of 27.75%. Staff's formula is mathematically equivalent to the *AEP* formula of $MVA^2 = MW^2 + MVAR^2$ solved for $MVAR^2/MVA^2$ (i.e., $MVAR^2/MVA = 1 - MW^2/MVA^2 = 1 - pf^2$. Staff I.B. at 25; Ex. S-9 at 12:18. Though Chehalis submitted that the *AEP* method using nameplate values, Staff alleges that the formula Chehalis actually used is the following:

$$MVA_{notNameplate,notTested} = \sqrt{\left(MW_{GenTest}^{\;2} + MVAR_{GenTheoreticalNameplate}^{\;2}\right)}$$. Staff R.B. at 36.

### 2. Discussion

35. The production of electric power in an AC (alternating current) power system includes both real and reactive power. In mathematical terms, electric power is a complex quantity and thus can be divided into its two constituent parts: real power, measured in watts (W) and Reactive Power, measured in volt-amperes reactive (VARs). Reactive Power is used or "consumed" by the power system to provide a stable voltage profile and is required to establish electric fields in facilities, such as transmission lines and electric motors. In short, reactive power is necessary to provide reliable, stable electric power for all purposes. Reactive power is supplied both by generators and by devices such as inductors and capacitors that are connected to the transmission system. The cost of the transmission devices owned by the Transmission Provider is recovered in the Transmission Provider's transmission tariff rate as part of transmission service. The costs for generators to supply reactive power are ultimately recovered by the Transmission Provider through the Transmission Provider's ancillary service Schedule 2

as set forth in the FERC pro-forma Open Access Transmission Tariff (OATT). CPG-1 at 10.

36. The TransAlta Settlement required the parties to follow the Current *AEP* Methodology in calculating the allocation of generating plant between real and reactive power in determining the investment in generation to be charged the transmission customers as their costs of reactive power under Schedule 2. Chehalis claims to have done so on the basis of an allocation factor of $MVAR^2/MVA^2$, or reactive power capability squared, divided by the apparent power capability squared, as in Opinion No. 440. In that Opinion, however, the Commission approved AEP's use of the nameplate ratings on the generator for the apparent and reactive power capabilities.

37. Here, Chehalis claims that using the generator nameplate ratings would not be appropriate, as the generators are matched with turbines that are undersized and cannot reach their full rated real power. Their expert Honeycutt, therefore, calculated the apparent power by using what he referred to as the rated turbine real power, which is less than the generator real power rating, and applied it to the manufacturers' curves for the generators, which show the maximum reactive power output for each level of real power production. Ex. CPG-1 at 15-16.

38. According to these curves, when the real power production is reduced, the maximum reactive power production is increased. Exs. CPG-25, CPG-26. Using the lesser (than generator nameplate) real power figures, he found a greater reactive power production, and calculated new apparent power capability figures, using the appropriate formula of $\text{Apparent Power}^2 = \text{Real Power}^2 + \text{Reactive Power}^2$. In that the *AEP* methodology allocates plant investment between real and reactive power capability, the lesser real power capability and the greater reactive power capability would each, even considered independently, allocate a greater proportion of plant to reactive power capability. More precisely, the allocation to reactive power capability is based on a comparison of that capability to apparent (total) power capability, but not strictly in proportion because the units for each are different, MVARs and MVAs, and their numbers are squared pursuant to the Pythagorean theorem to arrive at the allocation, $MVARs^2/MVAs^2$.

39. Using the reduced real power production and the increased reactive power production, Chehalis arrived at power factors for the turbines of 0.80 and 0.78, instead of 0.85, the nameplate power factors for the generators themselves. Chehalis' calculation results in an allocation of 38.7% of plant to reactive power capability.

40. BPA and Staff, however, claim that the Current *AEP* Methodology required by the Settlement Agreement requires the use of the generator nameplate power factor, as was used by AEP in Opinion No. 440, which is 0.85 for each of the generators here. According to their calculations, this would result in an allocation of 27.75% to reactive

power, rather than 38.7%, which they claim is unreasonable and inconsistent with prior Commission decisions. BPA R.B. 18; Staff I.B. 25. BPA's expert F. Steven Knudsen testified that every other generator that has filed under the *AEP* Methodology has used the generator nameplate power factor (Ex. BPA-11 at 7), which in Opinion No. 440 resulted in a 21% allocation for AEP, compared to Chehalis' claimed 38.7%.

41. BPA asserts further that its witnesses David L. Gilman and Knudsen have clearly demonstrated that under certain conditions (which conditions are not rare or unique), the project is capable of producing significantly higher levels of real power than relied on by Chehalis, and that such higher levels of output were guaranteed by the project contractor. BPA R.B. at 23. BPA points to actual operating data to demonstrate that the plant had a maximum metered output greater than the turbine limitations claimed by Chehalis. BPA I.B. at 20.

42. In addition, BPA claims that, contrary to Chehalis' filing, the two gas turbine generators cannot operate at the 0.78 power factor implicit in Chehalis' calculation, as the generator step-up transformers (GSUs) for these generators are rated at only 210 MVA, and Chehalis used 221.8 MVA in the calculation. Therefore, the GSUs could not deliver the reactive power that Chehalis claims could be produced by the generators. BPA R.B. at 22.

43. There are no data showing that Chehalis actually produced the amount of reactive power for which it claimed capability, as the conditions on the system were never such that would permit it. Ex. CPG-32 at 19. The voltage on the BPA transmission system was already close to a high normal operating level. *Id.* Chehalis operated at an average power factor level in excess of 0.998. Ex. S-16.

44. Chehalis first argues that BPA and Staff misapplied the *AEP* methodology by using nameplate power factors rather than an allocation based on $MVAR^2/MVA^2$. Chehalis I.B. at 27; R.B. at 18. But, to the extent that the objection is to beginning the calculation with the power factor rather than the values for reactive power and apparent power, it is mere quibbling in that the formula can be expressed in a number of ways, as long as the proper values are utilized. The relevant question is what values should be utilized.

45. In arriving at a power factor of 0.85 for the allocation, Staff and BPA utilize the generator nameplate values which assume full generator capability of producing the generators' rated real power. In opposition, Chehalis claims that the real power capability must be limited to what the turbines permit the generators to produce. It utilized the rated turbine real power to begin its calculations. Chehalis R.B. at 18.

46. On a theoretical level, at least, Chehalis' position has merit, in that Chehalis invested in an entire system, not just in generators, and there is no capability in the generators beyond what the system permits.

47. And, as to the actual operations data used by BPA to show a higher output of real power than the limitations claimed by Chehalis, Chehalis points out that BPA used high values, rather than the midpoint values used by Chehalis, and values based on operating with fuel oil, which could only be used as a backup and for testing. *Id.* at 21.

48. Chehalis is correct that these data are inappropriate. One would have to assume normal operating conditions when the plant might be called upon to supply reactive power for transmission needs.

49. What Chehalis has failed to adequately counter, however, is BPA's allegation that the GSUs cannot deliver to the transmission system the full reactive power production for which Chehalis claims capability. Apparently, Chehalis does not dispute this assertion on a factual basis. Its response is limited to a reliance on the *AEP* case, where both the Initial Decision and Opinion No. 440 determined that the reactive power capability to produce VARs should be measured at the generator terminals, rather than at the GSU terminals nearest the transmission system, after some of the reactive power is lost to internal plant load. *Id.* at 19. Chehalis states that what BPA fails to take into account is that reactive power is used to serve plant load and is consumed by the GSUs themselves, as was the basis for the AEP determination. *Id.*

50. But Chehalis misapplies that decision to the facts in this case. There, the decision concerned reactive power capability that was all usable for transmission purposes, with part of it necessarily lost to internal plant load and the rest available for delivery to the transmission system. Here, there apparently is capability to produce reactive power in excess of what is usable, including as usable the portion that can be assumed will be lost to internal plant load. How much that latter amount may be, Chehalis did not attempt to establish, and we can only assume for purposes of this case that it is a negligible portion of the difference between the capability of the generating system to produce reactive power and the capability of the GSUs to deliver it to the transmission system. And as to that difference, which cannot be used for the benefit of the transmission system, there is no justification for charging the transmission customers under Schedule 2.

51. As is apparent, once we start down the slippery slope of modifying the nameplate specifications for the generator, utilized in Opinion No. 440, to take into account limitations attributable to other elements of the system, it can take us in various directions. Apparently, with this in mind and in the interest of promoting conformity in treatment, the Commission expressed its desire, in *WPS Westwood, supra.*, at P 14, that generators seeking reactive power recovery use the method employed in *AEP*, so as to create a standardized method for all generators that would produce greater clarity in

future requests for reactive power recovery and more efficiently utilize Commission resources. Obviously, the Commission hoped that using the *AEP* methodology would obviate the need to conduct a detailed investigation, on a case-by-case basis, into each reactive power calculation, as we are doing here.

52. While *WPS Westwood* does not, necessarily, preclude a generator in a typical filing under Section 205 from deviating for good reason from the mechanics in *AEP* of using the generator nameplate specifications, including limitations imposed by other elements of its system, they are not strictly bound to the *AEP* methodology by agreement, as are the parties to the TransAlta Settlement.

53. Accordingly, taking into account the uncertainties in the capabilities of the Chehalis' system taken as a whole, as demonstrated by all of the participants, and recognizing that these uncertainties are what the Commission, in its declaration in *WPS Westwood*, and the parties, in their wording of the TransAlta Settlement, attempted to avert, the Settlement Agreement is best construed as including the specific use of generator nameplate ratings as part of the "Current *AEP* Methodology." Consequently, Chehalis' attempt to incorporate into the *AEP* methodology limitations that may be imposed on the system by the undersized turbines must be construed as a departure from the *AEP* methodology to which the parties to the Settlement Agreement are bound, and cannot be accepted.

54. One also cannot help but agree with BPA and Staff that an allocation of 38.7% of plant costs to transmission customers by Chehalis, instead of 27.75% using generator nameplate values, appears unjust and unreasonable. In Order No. 2003, the Commission determined that interconnection customers, such as Chehalis, should not be compensated for reactive power when operating within its established power factor range, since it is only meeting its obligation. 104 FERC ¶ 61,103 at P 546. The Commission, apparently, recognized that the production of reactive power is a normal incident of producing real power and necessary to maintain the viability of the real power for all purposes. It is only when the generator is called upon to operate outside of the power factor "deadband," which in Chehalis' case would be less than 0.85 lagging according to the generator nameplate, to aid the transmission system, that it should be compensated by transmission customers under Schedule 2.

55. Subsequently, in Order No. 2003-A, the Commission partially reversed itself and permitted interconnection customers to receive compensation for reactive power within the established range if the transmission provider pays such compensation to itself or an affiliate. 106 FERC ¶ 61,220, at Art. 9.6.3. The Commission, apparently, was not prepared to withdraw from traditional utilities or their affiliates, currently the transmission providers, the reactive power compensation it had granted them in Opinion No. 440, notwithstanding its late recognition that reactive power produced within the

deadband should not be considered for the benefit of transmission rather than a normal generation function.

56. Subsequently, in *Calpine Oneta Power*, L.P., 113 FERC ¶ 63,015 (2005)(*Calpine Oneta*), the Initial Decision explored the area and recommended that reactive power be refunctionalized from transmission to generation based on regulatory, economic, cost causation and engineering principles in that its primary functions and purpose are to further and protect real power production, as spelled out in that decision. It recommended, accordingly, that, compensation be paid only for reactive power supplied when the generator is called upon to operate outside its standard power factor range, and not for reactive power capability.

57. On review, the Commission rejected that recommendation as beyond the scope of the proceeding. 116 FERC ¶ 61,282 at P 3. But it recognized that compensating generators on the basis of capability may not be appropriate in all circumstances, and it permitted the transmission provider in that proceeding, Southwest Power Pool, Inc. (SPP), and other parties, to propose a rule that would compensate generators only for reactive power actually needed and used for transmission. *Id.* at P 50.

58. On December 26, 2006, SPP filed a new tariff that would compensate generators only for reactive power actually supplied outside an established power factor range. *See* Docket No. ER03-765. Similarly, Entergy Operating Companies, operating in a number of states, have filed tariffs which reduce the compensation for reactive power supplied within their proposed power factor range to zero for themselves, their affiliates, and interconnected merchant generators. In a declaratory judgment, the Commission approved their tariffs. *Entergy Services, Inc.*, 113 FERC ¶ 61,040 (2005). In *KGen Hinds LLC*, 117 FERC ¶ 63,004 (2006), the Initial Decision upheld that tariff revision against a number of independent power producers (IPPs) who claimed that it violated their interconnection agreements. The decision has not yet been reviewed.

59. In the instant proceeding, Chehalis operates close to unity, at an average power factor during the test year between 0.998 lagging and -0.999 leading, well within the nameplate power factor ranges of its generators and within any conceivable range that could be set by a transmission provider. Ex. S-16 at 3. Any operation outside that range was rare and presumably only on start-up or shut-down. *See* Ex. BPA-10. Moreover, not only had Chehalis never been required to operate outside its normal power factor range, it had never even been called upon by BPA to supply reactive power to the system other than what was needed for its own real power. Tr. at 295.

60. It is clear that the allocation of 38.7% of the costs of the generation plant to transmission customers, as Chehalis proposes, is unreasonable in that none of the reactive power it is capable of producing is actually used, or contemplated for use, for transmission purposes. But why should BPA consider as reasonable the 27.75%

allocation that it voluntarily permits Chehalis under its tariff, and a similar allocation to other generators who, undoubtedly, offer no greater reactive power service to the transmission system? There is clearly a need for BPA to reconsider its tariff, as SPP and Entergy Operating Companies have done, and eliminate payments to companies for their capability to provide reactive power that is not needed or useful to the transmission system other than for the generating companies' own needs, even if some of the generating companies which benefit from the current tariff are fellow governmental entities. BPA should consider carefully its obligations to the rate-paying public.

## C. Specific Items in Total Production Plant and Accessory Electric Equipment

### 1. Positions of the Parties

*Chehalis*

61. Chehalis asserts that its Total Production Plant of $344,537,248 is correctly calculated. Chehalis I.B. at 32; *see* Ex. CPG-4 at 1:22.

62. Chehalis contends that it is appropriate to include the costs for the BPA kV Switchyard as Accessory Electric Equipment in the Total Production Plant as the BPA 500 kV Switchyard is the point at which reactive power can enter BPA's transmission system from the Chehalis facility, and "absent this facility, no reactive power would flow to the transmission system." Chehalis I.B. at 33, *quoting* Ex. CPG-32 at 20:15-16. Chehalis claims that the nature of these costs are similar to those associated with Chehalis' substation, necessarily incurred to deliver both reactive and real power to the transmission system. *Id.* at 33-34.

63. As an IPP, Chehalis explains that it incurs costs for limited transmission related service that cannot be recovered under an OATT. According to Chehalis, these types of costs were not addressed in the context of the Reactive Service charge in *AEP* because the costs of such facilities were already being recovered in AEP's transmission rates; and here, the costs are not recovered in BPA's rates. Further, Chehalis mentions that the Commission has permitted recovery of similar facilities in the Reactive Service revenue requirement of the Ontelaunee Energy Center in Docket No. ER03-624-000. *Id.*

64. Chehalis claims that the Transmission Line Reservation Fee costs are appropriately included in the Total Production Plant. Chehalis argues that the reservation was necessary during the construction of the Chehalis facility in order to guarantee that the Chehalis facility could deliver the supply of reactive power to the BPA transmission system. While Chehalis recognizes that non-firm transmission can be used, it contends that the transmission would have to be available on a consistent basis (i.e. firm), so that reactive power could reach the transmission system. *Id.* at 34-35.

65. Chehalis argues that its incurred costs for its substation are appropriately included in Accessory Electric Equipment. Chehalis argues that such costs are necessary to deliver both reactive and real power to the BPA transmission system. Chehalis asserts that the Commission has permitted recovery of such costs in Reactive Service rates, and should allow so here. *Id.* at 41.

66. Chehalis similarly argues that the costs incurred for the facility's Natural Gas Interconnection and Metering are appropriately included. Chehalis explains that such costs relates to the construction of natural gas pipeline and metering equipment located on Chehalis' property, which are essential to the operation of the Chehalis facility and the production of reactive power. *Id.* at 35-36.

67. Chehalis argues that the $900,000 is correctly included in the Total Production Plant. Chehalis asserts that the payment represents a portion of the development costs for the Chehalis facility for the construction of the plant that were not otherwise included in the costs in the filed rate. *Id.* at 36.

68. Chehalis argues that its cost of installation should be included in Total Production Plant. Chehalis explains that as a merchant generator, it is not required to file a FERC Form No. 1 with the Commission, but nonetheless tracked the costs it incurred in connection with the development, construction and operation of the Chehalis facility. Chehalis did not build the facility itself. *Id.* at 36-37. Rather, Chehalis acquired the land, and it contracted with Parsons Energy & Chemicals Group Inc. for engineering and procurement services and The Industrial Company for construction services. *Id.* at 37. Under this arrangement, Chehalis does not have the level of cost breakdown it would otherwise have if it had constructed the facility itself. Nevertheless, Chehalis contends that the actual costs from Chehalis' contractors were verified and provide a reasonable basis to allocate installation costs. *See* Ex. CPG-10. Where there were differences in cost, Chehalis states it used the lower amount. *Id.* at 38-40. Chehalis asserts that the cost of installation should be included in Accessory Electric Equipment as Account 345 provides for installed cost. *Id.* at 42.

*Bonneville Power Authority*

69. According to BPA, Chehalis has improperly included the cost of the BPA 500 kV Switchyard, as well as the Chehalis Switchyard, in the total costs assigned to Accessory Electric Equipment. Under the Current *AEP* Methodology, BPA asserts that these costs should be included under FERC Transmission Account 353 rather than Accessory Electric Equipment Account 345. *Id.* at 24-25.

70. BPA argues that the Transmission Line Capacity Reservation Fee, though itemized as a construction cost, is actually a cost associated with the purchase of tariff transmission services, and thus, the should be excluded from Total Plant Production.

Further, BPA argues that Chehalis failed to demonstrate that the reservation fee can reasonably be allocated to the provision of reactive supply; and that non-firm transmission would have been adequate to enable delivery of reactive power. *Id.* at 25-26.

71. Similarly, BPA claims that the Natural Gas Interconnection and Metering costs should be excluded from Total Production Plant because these costs are associated with the purchase of pipeline transmission services, and do not constitute construction or production costs. Rather, BPA submits that these costs reflect payments to Williams Northwest Pipeline for the transmission and delivery of natural gas. *Id.* at 26-28.

72. BPA asserts that the $900,000 payment represents a partial refund of monies advanced to Chehalis, by BPA, in consideration of a ten-year option to purchase power from the plant. BPA explains that under a project development agreement, Chehalis was required to partially reimburse BPA for its previous payments if BPA cancelled the option agreement prior to its expiration in 2005. BPA submits that, as a payment associated with a commercial power purchase arrangement, the refund is not a proper cost to assign to production plant in service. *Id.* at 28. However, if the Commission determines that the payment was an allowable cost of construction, BPA asserts that Chehalis must recognize additional payments made by BPA to Chehalis that are equivalent contributions in aid of construction, and that those payments total more that the $900,000 payment and accordingly, Chehalis would be required to reduce the cost of Total Production Plant. *Id.* at 28-29.

*Commission Trial Staff*

73. Staff argues that the BPA 500 kV Switchyard should not be included as a cost in Chehalis' Reactive Power Service rate in general and specifically excluded from Chehalis' Total Production Plant for three reasons. First, Staff argues that it does not perform a production function; rather it performs a transmission function. Second, the power generated at the Chehalis plant has already been transformed to a high voltage that can be transported over the BPA transmission system to serve load. Third, Staff asserts that the BPA 500 kV Switchyard contains equipment, including circuit breakers and disconnecting switches, which are used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits and better fits into FERC Account 353, a transmission account. For these reasons, Staff argues that the BPA 500 kV Switchyard costs should not be allocated to Accessory Electric Equipment. Staff I.B. at 28-30.

74. Staff argues that the Transmission Line Capacity Reservation Fee is not related to the production of electric power, and therefore does not belong in Chehalis' Total Production Plant calculation. According to Staff, this fee allowed Chehalis to transmit its power for real power sales, not produce reactive power. *Id.* at 31-32.

75. Similarly, Staff maintains that the Natural Gas Interconnection and Metering costs are unrelated to the construction or the production of reactive power should not be included in the Total Production Plant. *Id.* at 32-33.

76. It is Staff's position that the $900,000 payment should not be included in Total Production Plant. Staff claims that there is nothing in the record to substantiate witness Honeycutt's statement that the $900,000 payment was a reimbursement to BPA for development costs initially paid by BPA that Chehalis could have included in its total project costs.

77. According to Staff, Chehalis failed to provide sufficient accounting detail to support allocation of the installation costs to its Total Production Plant and that they should instead be included with the balance of the plant. *Id.* at 35-37. Staff states that the exhibits Chehalis included to support its allocation of installed cost were prepared by a third party and its witness Honeycutt could not testify to the accuracy of the data. Staff also submits that the costs Chehalis claims for its Engineering Procurement and Construction contracts do not equal the Project Total shown on Exhibit No. CPG-10 at 2:8. *Id.* at 36.

### 2. Discussion

a. <u>the BPA 500 kV Switchyard</u>

78. As the participants all agree, this facility is transmission equipment, the costs of which would be included under FERC Transmission Account 353 and not under any of the plant production and accessory equipment accounts that were addressed in *AEP*, *supra*. Chehalis asserts that this was because the costs of such facilities were already being recovered in AEP's transmission rates. Chehalis I.B. at 34. Chehalis is an IPP and not also a transmission provider as are traditional utilities like AEP, and it does not have an open access transmission tariff under which it can recover those transmission costs. It would use Schedule 2 to pass those costs through to transmission customers.

79. As equitable as it may appear, Schedule 2 is not a catch-all on which generating companies can pass through to transmission customers all transmission costs for which there is no other mechanism. To be includible, costs must be related specifically to reactive power service, at least by some logical allocation, as with the reactive power capability component of production plant. Chehalis has failed to demonstrate any such connection. More conclusively, Chehalis can include only what was part of the Current *AEP* Methodology, as defined in the Settlement Agreement. As this item was admittedly not included and is not related to the production of reactive power, Chehalis cannot include it here.

b. the Chehalis Substation

80. This item is on all fours with the BPA 500 kV Switchyard, as the parties appear to agree. It is a transmission facility whose costs would be included in FERC Transmission Account 353 if Chehalis had maintained accounts according to the FERC's Uniform System of Accounts. Its cost is a transmission expense, but not includible in Schedule 2 for the same reasons applicable to the BPA 500 kV Switchyard, above.

c. the Transmission Line Capacity Reservation Fee

81. During the construction of the plant, Chehalis made three payments to reserve Long Term Firm Point-to-Point service. It claims that the fees should be included in Total Production Plant because without the certainty of reservation there would be no certainty that it could deliver reactive power to the transmission system. Ex. CPG-32 at 21; Chehalis I.B. at 35.

82. Chehalis' claim has no merit. Generators are permitted to pass reactive power costs on to transmission customers only because reactive power is assumed to benefit the transmission system, as Chehalis agrees (Tr. at 294). When Chehalis' generators are operating to produce real power, whether for firm or interruptible service and in whatever amount, their operations can be tailored to produce reactive power up to system capability. *See* Chehalis' generators' capability curves at Exs. CPG-25, CPG-26. The transmission provider can then call on Chehalis to provide whatever reactive power the transmission provider needs, within Chehalis' capability, to safeguard the transmission system, by requiring Chehalis to maintain the transmission provider's desired voltage schedule. Tr. at 81, 294-95.

83. Chehalis has offered no reason why the transmission provider would forego the opportunity to safeguard its own transmission system by not availing itself of Chehalis' capability of providing the reactive power in whatever amount it needs because Chehalis has not paid it a reservation fee. *Id.* That reservation fee was paid solely for Chehalis to transmit its real power, not to transmit reactive power to serve transmission. It is the transmission provider, not Chehalis, that may need reactive power for transmission purposes, and, if Chehalis' generators are in operation, it will schedule it regardless of whether Chehalis has reserved any capacity on its transmission system.

84. If Chehalis were not transmitting real power, there would be no need for its reactive power. It is not required to maintain its plant in operation to produce reactive power. And there is no indication that there was even another producer of real power nearby on the transmission provider's system for whom Chehalis' reactive power would be useful or needed. Clearly, the reservation fee served only Chehalis' purpose of selling its real power, and was unrelated to reactive power service. It cannot be included in Schedule 2.

d. Natural Gas Interconnection and Metering Cost

85. Chehalis included the amount of $1,884,344 for Natural Gas Interconnection and Metering Costs in Total Production Plant, of which a portion is attributed to generation, for allocation between reactive power and total power, with the reactive power sum charged to transmission customers in Schedule 2, as discussed above. At hearing (Tr. at 79-80) and now on brief (Chehalis I.B. at 35, n.16), Chehalis concedes that the amount should be revised to $1,233,524.57, as it had erroneously included $650,819.43.

86. There is no question that construction costs paid by Chehalis for these facilities should be included in Total Production Plant, as the facilities are used to further Chehalis' production of power, and not for Chehalis to transport and deliver natural gas. The problem is that Chehalis has not documented any costs that it incurred in constructing these facilities. It appears from the Chehalis' data responses (Ex. BPA-33) and its expert's testimony at hearing (Tr. at 79-80) that Northwest Pipeline Company built the facilities, which it owns, at an estimated cost of $650,000, and charges Chehalis an annual fee of $1,239,096 for service, corresponding closely to the amounts that Chehalis concedes and claims, respectively, above.

87. Neither the costs of current operations, nor the investment costs incurred by others, is includible in Chehalis' Total Production Plant. If Chehalis actually incurred any construction costs for the facilities, it has not substantiated them.

e. the $900,000 payment to BPA at closing

88. Chehalis included in Total Production Plant a $900,000 payment to BPA. In response to a BPA data request, it described the payment as being for the purpose of terminating an Option Development Agreement so that it could proceed with the Chehalis project. Ex. BPA-45. In agreement, BPA expanded on the purpose of the payment as being in partial refund of monies advanced to Chehalis by BPA in consideration of a ten-year option to purchase power from the plant that was granted to BPA by Chehalis. Ex. BPA-11 at 38.

89. As BPA argued (*Id.* at 38-39), it would be improper to include the payment in cost of production plant, in that the payment was associated with a commercial power purchase, not the construction of the generating project.

90. After first testifying consistent with this understanding of the payment, as being for the purpose of removing any claim that BPA might have on the project (Tr. at 102), Chehalis' witness Honeycutt changed his story. Later in the hearing, he testified (and not with great clarity) that they were in the nature of a repayment to BPA for payments BPA had made for project costs. Tr. at 308-09. It should be noted that BPA had previously

indicated in its pre-filed testimony that, if this payment were considered as an allowable cost of construction, there were additional payments, greater in amount than this, going from BPA to Chehalis that should be considered in aid of construction and would have the effect of reducing Chehalis' filed rate by more than the $900,000. Ex. BPA-11 at 39.

91. Under the circumstances, Chehalis' latest version of the payment lacks credibility. Moreover, the tactic of an 11th hour change in story with no opportunity to investigate, discover, and prepare rebuttal testimony and cross-examination cannot be accepted. As I have pointed out before when confronted with this tactic, "[i]n the unlikely event that the subsequent testimony, however imprecise, is the more accurate one, this would not be the first case or issue lost by poor trial preparation, and in this case, deservedly so. [The parties] should have taken greater pains to protect their interests." *AES Ocean Express v. Florida Gas Transmission Co.*, 115 FERC ¶ 63,009 (2006).

92. That is not to say that when counsel and company experts do sometimes err to the undeserved detriment of their client or employer, some allowance should not be made. In such a situation, where the injury would be substantial, the claim seems credible, and the error understandable, further hearing may be in order, preceded by an allowance of adequate trial preparation to opposing counsel. But none of these factors are present here. Consequently, the subsequent testimony is not accepted. The payment is found to be a return of monies paid for a power purchase and is not a construction cost that may be included in Total Production Plant.

f. <u>costs of installation</u>

93. Although the record is not entirely clear, it appears that we are dealing in general with the costs of installing the generating plant and accessory electric equipment, and that Chehalis used multipliers slightly exceeding 100%, applied to the plant and equipment costs, to arrive at the direct and indirect costs of installation. Staff contends that Chehalis has insufficient documentation to support the claimed amounts and that they are unreasonable.

94. To begin with, Staff claims that the costs that Chehalis claims it paid for its Engineering Procurement and Construction contracts (Ex. CPG-63 at 5-6) do not equal the Project total shown on Ex. CPG-10, page 2, line 8. As I view the documents, however, I see identical figures on each. During prehearing proceedings, Staff did discover discrepancies between the figures shown on the purchase order list from its contractor and the schedules supplied by the contractor on which Chehalis bases its computations, but they amounted to less than 1 percent and are of no significance as to their effect on the amounts claimed by Chehalis or on the reliability of the figures. See Ex. CPG-32 at 24-26.

95. More importantly, Staff questions the magnitudes of the multipliers, which result in the costs of installing the equipment slightly exceeding the costs of the equipment themselves. Staff asserts, and Chehalis' witness Honeycutt agrees (Tr. at 210-11), that similar multipliers, which here slightly exceeded 100%, amounted to 17.93% in *AEP*, *supra*.

96. Staff and Honeycutt refer to the figures in Schedule 1C in Ex. CPG-63 at 4. Specifically, column E, Owner Cost, which includes the equipment costs and the add-ons now in question, is slightly more than double the equipment costs shown in column B. On line 1, for example, the Equipment Cost for the GE CT1 is shown as $36,889,650, and the Owner Cost is shown as $77,557,426, indicating an add-on of $40,667,776, or 110.24%. It is this figure of 110.24% that Staff apparently equates with the 17.93% in *AEP*. The reason for the great discrepancy between Chehalis' calculation and that of AEP is that AEP excluded all but labor costs from its add-on (Ex. S-29), while Chehalis includes all costs (Ex. CPG-63 at 5-7).

97. Staff contends that because the multipliers are far from conservative and reasonable, and because Chehalis did not account for the installed costs in the detail necessary to support assigning them to the reactive portion of equipment, the cost should be included only in balance of plant, not in production plant and accessory electric equipment. Staff. I.B. at 37. If included in balance of plant, only a small percentage would be assigned to reactive cost attributed to production plant, against which the reactive allocator would be applied. See CPG-63 at 1, line 24.

98. But that is a harsh remedy, considering that a portion of the add-ons consisted of the costs of the labor of installing the generating equipment, which was included in Total Production Plant and Accessory Electric Equipment in *AEP*. If Chehalis can break those amounts out of its add-on amounts to Staff's satisfaction in a compliance filing, with supporting documentation, it should be entitled to include those amounts in Total Production Plant and Accessory Electric Equipment, with the remainder going to balance of plant.

99. If it cannot, I would fashion another remedy as an alternative. In *WPS Westwood*, *supra*, the Commission indicated that, if the IPP is not on the Uniform System of Accounts and does not have actual cost data and support, a proxy would be used. 101 FERC ¶ 61,290 at P 15. While the Commission had in mind a proxy for the entire calculation, there is no reason why a proxy could not similarly be used in part, such as for the multiplier. If what Staff and Honeycutt appear to agree on were true, that the multiplier in *AEP*, *supra*, comparable to the 110.24% add-on used by Chehalis was 17.93%, I would substitute 17.93% for the multipliers of slightly over 100% utilized by Chehalis for the assignment to Total Production Plant and Accessory Electric Equipment, and assign only the remaining 82.07% to balance of plant, of which a small portion would then be allocated to reactive power producing facilities.

100. If Chehalis cannot satisfy Staff in a compliance filing that it can apply either alternative, all of the amounts claimed as costs of installation should go to balance of plant, as Staff contends.

## D. Heating Losses Component

### 1. Positions of the Parties

*Chehalis*

101. Chehalis asserts that inclusion of the Heating Losses Component in its Reactive Service Rate is permitted under the TransAlta Settlement for several reasons. First, the TransAlta Settlement does not expressly state that it precludes recovery of the Heating Losses Component. Chehalis I.B. at 18. Second, inclusion of a Heating Losses Component is standard in the majority of Reactive Service filings of IPPs. Third, Chehalis argues that Commission orders have permitted Heating Losses Component during the period covered by the Current *AEP* Methodology. For example, in *Duke Energy Fayette, L.L.C.*, 104 FERC ¶ 61,090 at P 13, 17 (2003) and *Conectiv Bethlehem, L.L.C.*, 106 FERC ¶ 61,272 at P 15 (2004), the Commission specifically reviewed the Heating Losses Component of each proposed Reactive Service rate and did not take exception to its conclusion. *Id.* at 23. Finally, Chehalis comments that the fact that other generators to the TransAlta Settlement did not include a Heating Losses Component is merely a reflection of their decision not to include the Heating Losses Component in their filings, and should not be interpreted as an indication of their intent with respect to the TransAlta Settlement. *Id.* at 25.

102. Chehalis' total annual heating losses revenue requirement is calculated as the product of MW heating losses, operating hours, and the hourly average price, totaling approximately $0.501 million. *See* Ex CPG-16 at 1:15; Ex. CPG-63 at 12. The GSU heating loss attributable to reactive power production was calculated by analyzing the difference in generator current at a constant level of real power production, with and without reactive power production. The combustion turbine generators calculations were based on the unity power factor and 0.78 power factor. For the steam turbine generator, calculations were based on the unity power factor and 0.80 power factor. *See* Ex. CPG-15 at 1; Ex. CPG-63 at 11. The incremental heating loss for the three Chehalis generators attributable to reactive power production is 1.296 MW while the incremental heating loss for the three transformers attributable to Reactive Power production is 0.708 MW. Ex. CPG-1 at 28:22 to 29:16; *summarized* at Ex. CPG-16 at 1. To measure Chehalis' cost of reactive power heating losses for the Chehalis facility, the hourly average price, $45.08 per MWh (Ex. CPG-16 at 1:15; Ex. CPG-63 at 12:15), was calculated based on the Dow Jones Mid-Columbia averaged index hourly prices for 2004 while the Chehalis plant was operating. Ex. CPG-1 at 29:17-23.

103. Chehalis asserts that the approach it followed to calculate the Heating Losses Component is consistent with other of other Reactive Service rate filings accepted by the Commission prior to February 16, 2005. Chehalis asserts that it is appropriate to base the incremental heating loss on the 0.78 and 0.80 power factors, not the maximum reactive power output as that the capability curves found in Exhibit Numbers CPG-25 and CPG-26 show that the maximum reactive power output occurs at a power factor less than 0.78 and 0.80 respectively. Chehalis I.B. at 62. Chehalis also asserts that its approach to use actual hours of operation data is consistent with the heating losses calculation in *Safe Harbor Water Power Corp.*, 102 FERC ¶ 61,272 (2003)(*Safe Harbor).* Chehalis also submits that costs and lost opportunity costs are appropriate to include in the Heating Losses Component and follows the example of other Heating Losses Components included in filings accepted by the Commission, including *Safe Harbor* and *Tenaska Virginia Partners*, 107 FERC ¶ 61,207 (2004)(*Tenaska). Id.* at 63. Chehalis argues that its approach is supported by *Dynegy Midwest Generation, Inc.*, 116 FERC ¶ 63,052 at P 156 (2006)(*Dynegy*) where it was determined that compensation for heating losses should be based on rated capability. Based on *Dynegy* , Chehalis claims that fuel costs and transportation costs are appropriately included in the Heating Losses Component. Chehalis R.B. at 49-51.

104. In order to adopt a Heating Losses Component based on a methodology other than the approach it proposed, Chehalis argues that the public interest standard must be met for Chehalis' rate as a whole. Chehalis adds that this burden is heightened because of the introduction of the Service Factor, which operates as a discount from a methodology used to determine a just and reasonable rate. *Id.* at 51.

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105. BPA's position is that the TransAlta Settlement does not authorize inclusion of a Heating Losses Component. BPA I.B. at 13. BPA claims that, by including a heating loss component in its rate, Chehalis intends to capture costs related to incremental heating losses in armature and field windings due to reactive flow, with an adjustment for stray losses due to eddy currents. *Id.* at 40. In the proceedings where the Commission has permitted Reactive Power Service rates to include a Heating Losses Component, BPA emphasizes that the heating losses components were submitted as entirely separate components of the rate, separate and apart from the fixed capability components that were calculated using the *AEP* methodology. *Id.* at 14-15. In addition, BPA mentions the February 4, 2005 Staff Report, entitled *Principles for Efficient and Reliable Reactive Power Supply and Consumption*, submitted in Docket No. AD05-1-000 (Staff Report), which described the *AEP* methodology as including only a Fixed Capability Component. Where generators sought to include other rate components, such as heating losses, the Staff Report described it as the "FPL Energy model," and did not considered it to be a modification or expansion of the *AEP* methodology. *Id.* at 15-16.

106. Even if permitted, BPA asserts that Chehalis has incorrectly calculated the Heating Losses Component. BPA charges that Chehalis improperly bases its losses on a hypothetical operating profile that assumes that the plant is operating at power factors of 0.78 and 0.80 for every hour of operation, though on average the plant operates closer to unity power factor. As a result, BPA states that the reactive heating losses are inflated when compared with the actual reactive heating losses. *Id.* at 41. In addition, BPA asserts that Chehalis erroneously follows a market-based approach to calculate heating losses, instead of the cost-based approach, as required. BPA explains that if the market price at any time is not higher than the equivalent cost of fuel, the Chehalis plant should not dispatch and would therefore not incur any heating losses. *Id.* at 41-42. Finally, BPA claims that Chehalis witness Honeycutt failed to offer any evidence that the heating losses associated with the Chehalis generators' production of reactive power has actually resulted in any foregone power sales. BPA I.B. at 42, *citing* Ex. BPA-11 at 27:8-17. According to BPA, the cost of additional fuel used for actual reactive output should form the basis of any opportunity cost associated with heating losses; and such opportunity cost of fuel should be based on actual reactive power production. *Id.*

*Commission Trial Staff*

107. Staff argues that the Current *AEP* Methodology, as referenced in the TransAlta Settlement, does not permit inclusion of a Heating Losses Component. Staff I.B. at 22. Staff states that the Commission did not issue any orders that have changed this methodology during the relevant time period. *Id.* Staff maintains that Chehalis' reliance on *WPS Westwood* for the proposition that the Commission intended heating losses to be part of the *AEP* methodology is misplaced. Staff asserts that *WPS Westwood* is referenced in the TransAlta Settlement because it sets forth the general Commission policy of applying the *AEP* methodology to reactive power rates. Staff argues that acceptance of the WPS Westwood Settlement did not constitute a determination on the merits, or establish any principals or precedent with regard to methodology. *Id.* at 23-24.

108. Staff asserts that Chehalis' proposed Heating Losses Component is overstated and far from just and reasonable. *Id.* at 72-73. First, Staff contends that Chehalis incorrectly assumed that the heating losses are based on the power plant's maximum capability to lose heat despite the fact that the plant typically is not operated at full reactive capability at all times. *Id.* at 73-74. Second, Staff maintains that by calculating its heating losses based on lost total revenues, not lost profits, and Chehalis places itself in a better position that it would have been if it had made the sales it claims it lost. *Id.* at 75-79. Since power was never produced, Staff contends that Chehalis did not incur the associated costs.

109. Staff also contends that the cases Chehalis cited in support of its calculation do not support inclusion of lost opportunity sales. Staff argues that *Safe Harbor* is easily

distinguishable because the Interconnection Agreement (IA) between Chehalis and BPA does not provide for lost opportunities, whereas in *Safe Harbor* the IA did account for lost opportunities. Staff also mentions that the inclusion of an annual heating losses revenue requirement in Safe Harbor's proposed rate was presumably not protested because Safe Harbor's proposed annual heating losses revenue requirement of $50,506 is approximately 1/40th of its total proposed Fixed Capability Component revenue requirement, while Chehalis' proposed annual heating losses revenue requirement of $500,663 is approximately 1/6th of its total proposed Fixed Capability Component revenue requirement (prior to the application of the Service Factor). *Id.* at 76. Staff states that Chehalis' reliance on *Tenaska* is also misplaced; in *Tenaska,* the Commission directed Tenaska to remove the lost opportunity cost component from its rate schedule as unsupported. Staff R.B. at 76, *citing Tenaska*, 107 FERC ¶ 61,207 at P 27.

110. Staff suggests that heating losses are variable costs, not fixed costs, and they should be based on actual operation as opposed to being based on an assumption that each unit is providing its rates (or maximum) reactive output during the hours that the unit is in operation. Under Staff's formula, as real power is reduced, reactive power is reduced:

$$(\textit{Heating losses @ Maximum MVAR and Maximum MW})\, x \,\frac{\textit{Average Actual MVAR}^2}{\textit{Maximum MVAR}^2}\, x \,\frac{\textit{Average Actual MW}^2}{\textit{Maximum MW}^2}$$

Staff I.B. at 74.

111. If it is found that the foregone sales method is appropriate to determine heating losses, Staff argues that Chehalis should only be compensated for lost profits, exclusive of costs. Under such circumstances, Staff suggests subtracting Chehalis' costs not incurred, $41.02 (cost per megawatt hour), from the market price, $45.08, for a total of $4.06/MWh. *Id.* at 78-79; s*ee* Tr. at 163-64; Ex. CPG-32: 68:1-6.

### 2. Discussion

112. As discussed in the fixed capability section, above, Chehalis allocates a portion of the costs of investment in plant to reactive power service in the proportion of reactive power capability to apparent (total) power capability, which it passes on to transmission customers on Schedule 2. Chehalis also attempts to pass on to transmission customers, on Schedule 2, the estimated costs of actually supplying the reactive power needed for transmission, which it claims as a "Heating Losses Component." It is so named because of the manner in which it is derived, from the calculation of the higher currents in the generator and GSU that are produced when they are operated at a power factor other than unity (1.0), and the resultant resistive heating and increased eddy currents (stray losses) produced in the generator and GSU by these higher currents. Ex. CPG-1 at 27. These resistive heating losses and stray losses can be used to calculate the real power that is consumed to produce reactive power and, from that, the cost that is directly attributable to reactive power production. *Id.*

113. Chehalis determined the heating losses by first calculating the difference in current that would be produced between running the generators and GSUs at unity (i.e., with no production of reactive power) while producing the maximum real power claimed by Chehalis, and running them at the power factors of 0.80 and 0.78, the maximum reactive power capability at full real power claimed by Chehalis, as discussed above. According to the manufacturer's curve, for the CTG units, at a constant real power of 172 MW, the CTG can produce 140 MVAR of reactive power. For the STG unit, at a constant real power of 176 MW, it can produce 133.4 MVAR. *Id.* at 27-28.

114. From the additional current and stray losses that would be generated by producing the maximum reactive power rather than running the generators and GSUs at unity (i.e., producing no reactive power), Chehalis then used industry and manufacturers' standards to calculate the additional MWs that would be consumed. *Id.* at 28-29.

115. Its final steps were to apply the average hourly price per MWh of $45.08 based on the Dow Jones Mid-Columbia index for 2004, to calculate the market price of the additional MWs consumed in the production of the reactive power, and then to multiply the result by the Service Factor of 63.1%, representing the percentage of time that the generators are assumed to be in operation. *Id.* at 29-30. In sum, Chehalis assumed that the generators would produce their maximum reactive power capability, rated at full real power production, every hour of their operation, and calculated the opportunity costs that would be lost by not being able to sell the MWs that were consumed as heating and stray losses in producing this reactive power.

116. Chehalis' position has no merit. To begin with, Section C.1.c. of the Settlement Agreement refers to the rate methodology established by the Commission in the Initial Decision in *AEP*, in the Commission's affirming decision in Opinion No. 440, and in *WPS Westwood*, as the "Current *AEP* Methodology. Ex. CPG-3 at §C.1.c. Section C.5.b. of the Agreement requires Chehalis to use that "Current *AEP* Methodology," in combination with a Service Factor, to determine its compensation when it files for a Reactive Power Service rate. That these decisions do not even mention heating losses is dispositive of Chehalis' claim. To accept Chehalis' perverse logic that the heating loss claim should be entertained because it was not specifically barred by the Settlement Agreement would open the door to a universe of claims on items similarly unmentioned in the Settlement Agreement and its cited decisions. Nor would it be proper to go behind the decisions to determine what the parties in those cases actually claimed or were allowed, as the published opinions were referenced, not anything more.

117. But even if the TransAlta Settlement had done just the opposite and permitted the merchant generators to include heating losses in Schedule 2, Chehalis would not be entitled to pass on any heating losses to transmission customers, because none had been incurred for transmission purposes. During the test year, the transmission provider never

required Chehalis to supply reactive power to the system other than what was needed for Chehalis' own generation. Tr. at 295. And, by merely eyeballing the graph of Chehalis' Power Factor Duration Curve (Ex. BPA-10), it is clear that the plant operated outside the its deadband power factor range (even using the manufacturers' power factor limit of 0.85 lagging) at considerably less than 1% of the time, and that, presumably, only when starting up or shutting down. It ran at average power factors exceeding 0.998 lagging and -0.999 leading, nowhere near the deadband limits. Ex. S-16.

118. As determined in Order No. 2003, *supra*, operating within the deadband is merely meeting the generator's obligation. It is not really performing a transmission function that should entitle it to compensation. And, there is no reason to believe that the figures with regard to the production of reactive power would be any different in the future than during the test year, except perhaps for normal growth in the system. Tr. at 281. In that none of the reactive power produced by Chehalis was used for transmission purposes in the test year and none could be expected to be used for those purposes in the future, none of the costs attributable to heating losses may be charged to transmission customers on Schedule 2.

119. Moreover, even if we assume, *arguendo*, that the contrary were the case and that the reactive power produced were used, and in its entirety, for transmission purposes, Chehalis would be entitled to claim only a miniscule amount of heating losses on Schedule 2. The half million dollars per year amount that it now claims overstates the costs actually incurred by a factor of hundreds.

120. Although there are other faults with Chehalis' calculation, the most critical item is its reliance on reactive power capability, an item totally unrelated to heating loss costs. It is one thing to allocate between generation and transmission the investment expenditures already incurred, or concerning which the magnitude has otherwise already been established, on the basis of capability to be used for either, as is permitted with the fixed capability component discussed above. It is yet another to attempt to peg the amount of an expense to a mere capability of incurring it and charging captive ratepayers for that capability when it is clear that the expense will never be incurred in any amount remotely approaching that magnitude.

121. As discussed above, Chehalis operated close to unity almost the entire time of operation. Moreover, it has yet to even approach, in any instance, its maximum claimed production of reactive power, because at no time did operating conditions permit it. Ex. CPG-32 at 19. Presumably, this experience extended even beyond the test year, as any evidence of capability to produce reactive power would be probative and material to this proceeding, whatever the period. And, even if Chehalis' generators had reached maximum reactive power production at any time, there is no evidence to suggest that it would be technically feasible for Chehalis' generators or any other generators to sustain maximum reactive power production for any continuous length of time, rather than

merely on an intermittent basis. Yet, with this certainty that its generators will not produce maximum reactive power every minute of its operations during the entire year, Chehalis has calculated its heating losses as though they would.

122. Even if we assume that Chehalis utilizes all of the reactive power it produces for transmission purposes, contrary to the evidence that it uses none, under traditional accounting, regulatory rules and simple logic, it must calculate its heating losses on the basis of reactive power actually produced in the test year. This production was reflected in its average power factor exceeding 0.998, rather than reactive power production at its assumed power factors of 0.80 and 0.78. Whether one does a straightforward calculation using the exact technique Chehalis proposed in its direct testimony, except for using actual production instead of maximum capability of producing reactive power, as Staff has done (Tr. at 478), or backs into the calculation using Chehalis' calculations, but substituting the actual 0.998 average power factor for the 0.80 and 0.78 capability power factors used by Chehalis, the result would be the same: the amount of heating losses calculated by Chehalis would be significantly reduced, by a factor of hundreds. *See* Tr. at 278-81, 341-44, 477-83; Ex. J-2.

123. According to Staff's calculation, which are undisputed on the mechanics, this would result in heating losses of 49.982049 MWh (Ex. S-16 at 1), as opposed to Chehalis' 11,106 MWh (Ex. CPG-16). If we accept Chehalis' market price of $45.08 per MWh, its correct heating losses amounted to $2,253, as calculated by Staff (Ex. S-16 at 1), rather that the $500,662.71 that Chehalis claims (Ex. CPG-16 at 1).

124. Additionally, Chehalis erred in multiplying the overstated MWhs that it calculated in heating losses by a market price on the premise that it had lost the opportunity to sell the MWhs on the market. It could only have lost the opportunity to sell them if it were otherwise operating at full capacity, which it did not do very much of the year. Tr. at 282-83. Conceivably, even if it had operated at full capacity for some of that time, it could have accommodated all of its sales opportunities and still produced maximum reactive power by operating for longer periods. Consequently, there is no evidence that Chehalis experienced any lost opportunity costs. It should have directed its calculation towards determining the variable costs of producing the additional MWhs, rather than at the costs of losing the opportunity to sell them.

125. Staff and Chehalis appear to agree that these costs amounted to $41.02 per MWh. Tr. at 157, 163-64; Ex. CPG-32 at 68; Staff. I.B. at 78. If we multiply the corrected amount of 49.982049 MWh by $41.02, the correct amount of heating losses incurred in the production of the reactive power was $41.02 x 49.982049 = $2,050.

126. But even if we accept the premise of lost opportunity costs, Staff contends that Chehalis overstated its losses by utilizing lost revenues, rather than lost profits. Staff I.B. at 78-79. Consequently, according to Staff, the heating losses should be calculated by

subtracting the costs Staff claims were not incurred ($41.02), from the market price ($45.08), to arrive at $4.06 per MWh in profit. *Id.* If that were the case, the heating losses would be reduced to 49.982049 x $4.06 = $203.

127. At first blush, Staff would appear to be correct that any recovery by Chehalis should be limited to lost profits. After all, Chehalis never would have had the opportunity to sell MWhs on the market without incurring the costs of producing them, and should only recover its profits, not the entire revenues. But this fails to take into account the fact that Chehalis has already incurred the heating costs in producing the reactive power and should be able to recover them in lost revenues, if it were entitled to recover lost opportunity costs (which it is not, as discussed herein). It is those costs, already incurred in production, that are being calculated as equivalent MWhs to measure Chehalis' heating losses for this proceeding. Hence, if Chehalis were entitled to compensation for its heating losses, it would either be as opportunity costs at the rate of $45.08 per MWh, or as variable costs at the rate of $41.02 per MWh. It would not be limited to a rate of $4.06 per MWh, the difference between the two, as Staff contends (*Id.* at 78).

128. Based on the discussion above, the correct amount of Chehalis' heating losses for the production of reactive power in the test year was $2,050. In that the Settlement Agreement did not allow a claim for heating losses and none of the reactive power was used for transmission, none of that amount may be claimed in Schedule 2. Chehalis' claim of half a million dollars per year in heating losses is an unconscionable attempt to charge transmission ratepayers for costs that it knows will never be incurred, except in a miniscule amount.

## E. Levelized v. Non-Levelized Approaches

### 1. Positions of the Parties

*Chehalis*

129. Chehalis argues that its non-levelized approach is correctly calculated and further, that its election to use it is fully consistent with the TransAlta Settlement. Chehalis asserts that the TransAlta Settlement does not explicitly state whether the Reactive Service is to be based on either a levelized or non-levelized approach. With the exception of *AEP*, Chehalis maintains that there were not any Commission orders that explicitly discussed either levelized or non-levelized in Reactive Service Filings during the period covered by the Current *AEP* Methodology. According to Chehalis, *AEP* does not require application of the levelized approach for reactive service. Rather, in *AEP*, Chehalis contends that the Commission permitted AEP to choose its methodology for all of its ancillary services on a levelized basis. Therefore, under the Current *AEP* Methodology, Chehalis asserts that its election is not restricted in *AEP* or any other

precedent applicable. Chehalis I.B. at 43-46. However, if a levelized rate is required, Chehalis states that it would take into consideration in a compliance filing Staff witness MaryAnne Leger's formula for the depreciation component as well as the equation for composite income tax factor. *Id.* at 46; *see* Ex. CPG-32 at 37:14-20.

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130. BPA characterizes Chehalis' proposed method as a "novel hybrid approach that is levelized in part and non-levelized in part." BPA I.B. at 30. BPA witness F. Steven Knudsen explained that, "consistent with the non-levelized method, Chehalis has used straight-line depreciation and a non-levelized recovery of income taxes; but consistent with the levelized method, Chehalis calculates its return on gross (undepreciated) investment." BPA I.B. at 32, *citing* Ex. BPA-11 at 16-24. According to BPA, the result is a revenue requirement that starts high and remains level over the serviced life of the equipment, and results in a depreciation component of the Fixed Charge Rate that is 360 percent higher than the depreciation component calculated under the levelized approach. *Id.* Further, BPA contends that if the rate does not decline over time as the investment is depreciated, the resulting rate will over-recover costs. *Id.* at 34.

131. BPA asserts that Chehalis should be directed to revise its rate calculation to utilize the levelized gross-plant methodology. BPA maintains that the Current *AEP* Methodology is based on the levelized gross plant approach to calculating an annual carrying charge. *Id.* at 32. According to BPA, the Commission specifically approved use of a levelized gross-plant methodology for determining a rate for ancillary services in Opinion No. 440, and further reiterated its policy that the *AEP* methodology uses a levelized approach in *Capline Fox*, stating "*Calpine Fox* properly applied the *AEP* methodology by calculating . . . the utilization of a levelized annual carrying cost approach to develop its annual revenue requirement." BPA I.B. at 30, *citing Calpine Fox*, 133 FERC ¶ 61,047 at P 16.

*Commission Trial Staff*

132. According to Staff, Chehalis is required to use the levelized method employed in Opinion No. 440. In support of its position, Staff notes that the other three generators that were parties to the TransAlta Settlement filed reactive power rates using the levelized approach, and that this is indicative of their recognition that the levelized approach was intended to be followed. Staff I.B. at 45. Staff maintains that despite the fact that *Calpine Fox* was issued on October 17, 2005, after the February 16, 2005 filing date, it is relevant precedent because it confirmed that the *AEP* methodology is the levelized methodology. Finally, Staff contends the Commission prefers a levelized approach because "[a] levelized charge is not time sensitive and thus establishes an appropriate benchmark for rates which will be in effect over an indefinite period." Staff I.B. at 46, *quoting Jersey Central Power & Light*, 38 FERC ¶ 61,275 (1987).

133. Staff contends that the depreciation and composite income tax factor formulas initially presented by Chehalis are incorrect and further, that Chehalis has agreed with Staff's suggested changes. Staff asserts that the correct formula for depreciation expense is $\frac{r}{(1+r)^n - 1}$, where r is the allowable overall rate of return on capital, and n is the number of years over the life of the facilities. And composite income tax factor is:

$$\frac{\frac{FedTX}{(1-FedTX)} + StateTX}{1 - StateTX} \times \left( r + \frac{r}{(1+r)^n - 1} - \frac{1}{n} \right) \times \left( 1 - \frac{WtdLTD}{r} \right)$$

, where FedTX is the federal income tax rate, StateTX is the state tax rate, r is the overall rate of return, n is the life of the facility (in years), and WtdLTD is the weighted long term debt rate. Under Staff's proposed formula, Chehalis' proposed factor is changed from 0.0296 to 0.0207. Staff I.B. at 47-48.

### 2. Discussion

134. As BPA's expert Knudsen describes it (Ex. BPA-11 at 15-17), the two fundamental approaches to recovering the capital cost associated with investments in utility assets are the non-levelized approach (also known as the non-levelized net plant method) and the levelized approach (also known as the levelized gross-plant method). Both approaches are based on a revenue requirement incorporating an annual carrying cost comprised of two components: (1) an annual equipment depreciation charge representing a recovery of invested capital, and (2) an annual return on unrecovered capital investment in the equipment. Chehalis used the non-levelized approach. BPA and Staff, however, claim that only the levelized method that AEP had used is permitted under the Current *AEP* Methodology.

135. Under the non-levelized approach, invested capital is recovered through equal annual depreciation charges over the useful service life of the equipment. This method of depreciation which is calculated by dividing gross plant investment (i.e., before any depreciation charges) by the service life in years, is called straight-line depreciation. Also, under the non-levelized approach, an annual return on investment is allowed on the remaining undepreciated capital investment in the equipment referred to as "net plant" (gross plant investment less accumulated depreciation).

136. Consequently, under the non-levelized approach, the revenue requirement will decline over the life of the investment as the equipment is depreciated.

137. Under the levelized approach, invested capital is also recovered through equal but smaller annual depreciation charges over the useful service life of the equipment. (This method of depreciation is also called sinking-fund depreciation.) Unlike the non-

levelized methodology, however, when it comes to calculating an annual return on invested capital, a return is allowed on the full original investment (gross plant) each year over the useful life of the equipment. Consequently, under the levelized approach, the allowed return on investment does not decline as the investment is depreciated. The sum of a level annual depreciation charge and a level annual return on investment achieves a level annual carrying cost. While a levelized revenue requirement approach will result in a somewhat lower initial revenue requirement than a non-levelized approach (due to the sinking fund depreciation charge being lower than a straight-line depreciation charge), the levelized approach results in a higher revenue requirement during the later years. The formula for determining a levelized revenue requirement is designed to produce a present value stream of revenues over the life of the equipment that is equivalent to the present value stream of revenues under the non-levelized approach, but the timing of cash flows is different.

138. The two methods also differ on the way in which the equity return is grossed-up for income taxes. The non-levelized approach provided for the recovery of income taxes on the full equity return each year. This results in a higher recovery for income taxes in the early years that declines over time as the plant is depreciated and the resulting total return on equity capital declines.

139. The levelized carrying charge approach employs a levelized income tax factor designed to return a constant level amount for the recovery of income taxes over the project life. This results in a lower rate component for recovery of income taxes in the early years than the non-levelized approach but a higher recovery of income taxes in later years.

140. Chehalis utilized the non-levelized methodology in calculating the amount to be passed through to transmission customers under Schedule 2. Staff and BPA contend that since, in Opinion No. 440, the Commission approved AEP's methodology and AEP had utilized the levelized methodology in calculating the charges to the transmission customers, it was part of the Current *AEP* Methodology under the TransAlta Settlement. They also point out, in confirmation of their interpretation, that the other three generators party to the Settlement Agreement filed for reactive power rates under the levelized methodology. Staff and BPA also rely upon *Calpine Fox*, *supra*, as specifically noting that the *AEP* methodology includes levelized rates.

141. In that Hearing and Suspension Order, the Commission stated (at P 16), as follows:

> We find that Calpine Fox properly applied the *AEP* methodology by calculating (1) the costs associated with the reactive portion of the generator/exciter system and the generator step-up transformers; and (2) the utilization of a levelized annual carrying cost approach to develop its

annual revenue requirement, and provides sufficient information for the Commission to evaluate Calpine Fox's proposed rates.

142. To Chehalis' argument that *Calpine Fox* was decided on October 17, 2005, after the February 16, 2005 filing date of the TransAlta Settlement, Staff responds that it would be outside the scope of the Settlement Agreement if it had modified the *AEP* methodology, but in that it merely confirmed what was true before October 17, 2005, it verifies that Chehalis has incorrectly used the non-levelized methodology. Staff I.B. at 45-46.

143. Of course, the Commission's subsequent interpretation of the *AEP* methodology, even if it were in a more authoritative final decision rather than a Suspension Order, throws no light on the parties' understandings when they signed the Settlement Agreement. But on that we have no direct evidence, as there was no testimony by anyone participating in the settlement, no documentation, nor anything in the wording of the Settlement Agreement that specifically addresses this point. In the construction of that Settlement Agreement, therefore, we must look to the totality of the circumstances surrounding the Settlement Agreement.

144. The most salient consideration is that any application of the non-levelized methodology that does not reduce net plant for subsequent periods overstates the revenue requirement. If the parties to the TransAlta Agreement had consciously considered the matter and permitted an election of the non-levelized methodology for the multi-year agreement, it is doubtful that they would not have specifically provided for a reduction to net plant for subsequent years, even if they had permitted updating as a general matter and not just for the Service Factor (contrary to the finding in this Decision). If, of course, they intended only an updating to the Service Factor, as decided here, it is even more likely that BPA would have rejected the non-levelized methodology if it had considered it as an option to the generators. But even if the participants to the Settlement Agreement had not consciously considered the question and had left it open, as is most likely, the Agreement should be construed as treating the levelized methodology as part of the *AEP* methodology, because permitting the non-levelized methodology in the reactive power calculation would be unjust and unreasonable and, given the choice, we should assume that the parties intended to do what was just and reasonable.

145. As Staff points out (Staff I.B. 46), the Commission favors the levelized methodology as a general matter, stating, in *Jersey Central Power & Light Company, supra.*, as follows:

> A levelized charge is not time sensitive and thus establishes an appropriate benchmark for rates which will be in effect over an indefinite period. It thus promotes rate stability without regard to the customer or the time of the transaction. A nonlevelized rate, however, must be revised

> periodically, since it front-loads the recovery of capital costs, *i.e.*, over time, depreciation reduces the investment base, and the rate necessary to provide a reasonable contribution to the seller's fixed costs declines.

38 FERC at 61,927.

146. Nevertheless, in the era of full regulation, now ended, the Commission had permitted companies to choose either methodology, a matter that is now ripe for review with regard to the reactive power calculation, if it has not already been decided definitively in *Calpine Fox, supra*. It is one thing to permit the non-levelized methodology when all of the company's operations are regulated. In that situation, the certain overstatement of investment costs passed on to ratepayers attributable to the failure to reduce net plant in the succeeding annual periods is likely to be offset in some degree by the expected increase in operations costs attributable to normal inflation that would not be passed on to them without a new filing. There is a balance of benefits to the utility and its customers, respectively, in not filing for new rates, albeit not an exact balance.

147. It is yet another thing in the era of deregulation to allow that overstatement of investment costs attributable to the failure to reduce net plant to be passed on when the investment costs are the sole or primary costs passed on to the ratepayers. The operations costs, for the most part, are borne by the company as part of its non-regulated business to be recovered in the sales of its real power generation. In that context, to allow generating companies to reap the unwarranted benefits attributable to the failure to reduce net plant in subsequent periods without a compensating downside would be unjust and unreasonable.

148. So, even if the parties to the TransAlta Settlement had not considered the levelized methodology as part of the Current *AEP* Methodology, it would be unjust and unreasonable for any unregulated generating company, whether or not subject to the TransAlta Agreement, to apply the reactive formula allocation to reactive power of the *AEP* formula on a basis other than the levelized methodology. This would especially be the case, here, where the parties to the Settlement Agreement could not update the calculation annually to reduce net plant, as appears the case under the language of the Settlement Agreement, but it would still be the case if they could update it and were required to reduce net plant during the term of the agreement. After the term of the TransAlta Agreement expires, it would still put the onus on the ratepayers to challenge, annually, the almost certain overstatement of costs passed on to them each year in Schedule 2.

149. Consequently, I find that the levelized methodology is part of the Current *AEP* Methodology under the Settlement Agreement, but that even if it were not, allowing Chehalis (or any other generating company with no aspect of its operations other than

reactive power being regulated) to apply the *AEP* allocation to reactive power on a non-levelized basis would be unjust and unreasonable. Accordingly, the non-levelized methodology is rejected, both because it violates the Settlement Agreement and because it is otherwise unjust and unreasonable.

150. There was some controversy early in the proceeding as to the mechanics of the differing methodologies, but they have apparently been resolved in the briefing, and no further finding is required.

## F. Cost of Debt

### 1. Positions of the Parties

*Chehalis*

151. Chehalis' actual capital structure consists of 100% equity; consequently, there is no embedded cost of debt. *See* Ex. CPG-1 at 22:20-21. According to Chehalis, since it does not have debt on its books and Suez, Chehalis' parent company, is an inappropriate proxy, a proxy is required to calculate Chehalis' cost of debt. In determining the appropriateness of a debt proxy, Chehalis witness Honeycutt applied two criteria, "[f]irst, the proxy should be transparent, *i.e.*, subject to verification from public sources of information. Second, the proxy should represent the actual costs of debt of IPPs doing business in the Pacific Northwest power market." Ex. CPG-1 at 23:20-22. Based on these criteria, Chehalis identified a proxy group consisting of the other generators subject to the TransAlta Settlement, Calpine and TransAlta. In accordance with Commission precedent, Chehalis asserts its proxy group consists of companies that are of "comparable risk . . . similar . . . in size, [and] business profile" in its proxy group. Chehalis I.B. at 49, *citing Southern California Edison Co.*, 92 FERC ¶ 61,070 at 61,265 (2000) (*SoCal Edison)*(emphasis added). However, since the cost of debt for these entities was not available at the time Chehalis submitted its initial testimony, Chehalis created a proxy group based on the parent entities of the IPPs subject to the TransAlta Settlement. *Id.* at 50.

152. Chehalis concludes that Staff's proposed cost of debt understates the cost of debt rate that investors would require to invest in Chehalis' reactive power operations, and this result undermines the principal in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope)* that there should be sufficient returns to service an entity's debt, and would ultimately lead to Chehalis' subsidizing BPA's customers. Chehalis finds several flaws with Staff's propose cost of debt. First, Chehalis asserts that Staff failed to establish that the Moody's Baa Utility Index is an appropriate proxy, and that its assertion that the Commission has used an investor service index yield as a proxy for the cost of long term debt for regulated utility service operations is unsupported. Second, Chehalis criticizes Staff's analysis because Staff's analysis is not based on Chehalis' risk

profile as a company, but instead what Staff deems to be Chehalis' risk in providing Reactive Service as a stand alone service. Third, Staff did not analyze the comparability of risk between the constituent companies of the Moody's Baa Public Utility Index and Chehalis. *Id.* at 53-56.

153. Finally, Chehalis argues that the use of BPA as a proxy is inappropriate because its risk profile is not comparable to Chehalis' risk profile. Chehalis explains that BPA receives significant benefits that flow from governmental ownership, which ultimately affect its financial profile. Second, Chehalis asserts that BPA is an inappropriate proxy because BPA controls a significant amount of federal-owned hydroelectric resources that keep BPA's rates low, whereas Chehalis, as a fossil-fired generator is subject to different risks. *Id.* at 58-61.

*Bonneville Power Administration*

154. BPA argues that the proxy companies Chehalis selected, TransAlta and Calpine, are inappropriate because they both have higher costs of debt and lower credit ratings than Suez. Further, Calpine's impending bankruptcy status renders it a significant credit risk. BPA asserts that when comparing the two sets of proposed costs of debt of the two Calpine subsidiaries (9.34% and 10.81%) and two TransAlta subsidiaries (6.75% and 6.7%) it is evident that use of TransAlta and Calpine as proxies is inappropriate. Also, BPA also asserts that both TransAlta and Calpine fail to meet Chehalis' "comparability criteria" as they are both large, multinational corporations in which Pacific Northwest regional activities are a small percentage of the companies' overall operations. BPA I.B. at 36-38.

155. Instead, BPA asserts that the Commission should require Chehalis to use either the cost of debt of Chehalis's parent company (Suez) use BPA's cost of debt as a proxy. BPA's cost of debt is 5.63 percent or 5.85 percent for the most recent six month period at the time of witness Knudsen's cross-answering testimony. *Id.* at 39. BPA recognizes that the Commission has not addressed using the interconnected transmission provider as proxy when it is an agency of the federal government. Nonetheless, BPA argues that its proposal is consistent with Commission precedent for approving generator filings that use as a proxy the capital structure, return on equity, and overall rate of return of the transmission provider to which the generator is interconnected. BPA asserts that its use as a proxy is further supported by Staff witness Green's theory that the cost of capital component should be sufficient to compensate Chehalis' investors for the risk of the plant's reactive power operations. BPA contends that as such risks are tied to the buyer's credit risk, with BPA's equivalent rating of an A rated utility, it presets a minimal credit risk associated with payment of reactive power service charges. *Id.* at 39-40.

*Commission Trial Staff*

156. Staff argues that the appropriate cost of debt for Chehalis' regulated reactive power operations is the Moody's Baa Public Utility Index yield of 6.36 percent. Staff contends that use of Moody's Baa Index is consistent with the earlier Commission findings that bond indices are reliable indicators of the average costs in the market. Staff I.B. at 61-62. Staff also states that its use of the most recent six-month average yield of Moody's Baa rates Public Utility Index is consistent with the Commission's preference for using recent market date in developing the return on capital. *Id.* at 63. Staff also highlights the fact that the rates at issue for reactive power service are regulated, and therefore, the rates should be based on data reflective of regulated operations, which are less risky than unregulated operations. *Id.* at 63-64. Under the TransAlta Settlement, Staff states that Chehalis is guaranteed payments for its fixed cost component, regardless of whether it actually provides reactive power, and Chehalis' reactive power rate is regulated by the Commission. *Id.* at 66, *citing* Ex. S-32 at 9. Thus, Staff advises that only factors related to the related to the regulated reactive power operations need be examined in setting the rates for Chehalis' reactive power operations.

157. Staff argues that Chehalis' proposed proxy group of Calpine and TransAlta is inappropriate. Specifically, Calpine's 2005 10-K indicates that it has been experiencing significant financial problems, including prices of debt and equity securities. Staff asserts there is no indication that Chehalis is facing such circumstances. Also, as Calpine and TransAlta engage in lines of business outside the utility sector, Staff argues that their business risk profiles are different than that of Chehalis. *Id.* at 53-60.

158. Finally, Staff maintains that BPA's proposal to use its cost of debt as the proxy is inappropriate. Staff states that the Commission has not addressed the issue of using an interconnected transmission provider that is a government agency as a proxy. Further, Staff asserts that BPA's status as an agency of the Federal government presents a unique risk profile, unmatched by any other entity, and as such, it is inappropriate to use it as the surrogate for the cost of an independent generator. *Id.* at 60.

**2. Discussion**

159. The TransAlta Settlement specified most of the elements of the capital structure to be used in performing its Current *AEP* Methodology calculation: Chehalis is required to use a ratio of 50 % equity and 50% debt, and to assume a return on equity of 11.0%. Ex. CPG-3 at 13. The cost of debt was left to be determined in the current proceeding.

160. In determining the cost of debt in an applicant's capital structure, the Commission normally will use the subject company's embedded cost of debt. *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,413-14 (1998) (*Transco*); *see also Kentucky West Virginia Gas Co.*, Opinion No. 7, 2 FERC ¶ 61,139 at 61,325-28 (1978) (*Kentucky West Virginia*). However, the capitalization for Chehalis is 100 percent equity. Ex. CPG-1 at 22. In circumstances in which the company itself cannot be used,

the Commission will rely on a proxy to set capital cost. *Transco*, 84 FERC ¶ 61,084 at 61,413-14; *Kentucky West Virginia*, 2 FERC ¶ 61,139 at 61,325-28. The proxy must exhibit risk similar to that faced by the applicant. *Consolidated Gas Supply Corp. v. FERC*, 653 F.2d 129, 133-34 (4th Cir. 1981). The Commission frequently turns to the parent company as an appropriate proxy. *New England Power Pool/USGen New England, Inc*., 92 FERC ¶ 61,020 at 61,041 (2000) (*New England Power Pool*); *Transco*, 84 FERC ¶ 61,084 at 61,413-14. If the parent company is unsuitable, some other source must be used to simulate the cost the subject company would pay for capital.

161. There were problems with the proxies used by each of the participants. BPA argues for the use of either Suez, the Chehalis' parent company, or itself, Chehalis' interconnected transmission provider. BPA I.B. at 36. But neither of the two is satisfactory. Suez is headquartered in France and has diversified operations worldwide. Ex. GPC-1 at 25. In no way does it resemble its IPP subsidiary, Chehalis. And BPA is a governmental entity with almost no market risk. They can be dismissed as proxies, out-of-hand.

162. Commission Staff proposes the use of Moody's Baa-rated Public Utility Index yield as the proxy. But the Commission has never used Moody's as a proxy for debt, except to confirm the reasonableness of a DCF analysis or the company's own debt. Tr. at 514-15. Moreover, the Public Utility Index covers only regulated companies and Chehalis is unregulated, except for its reactive power allocation. Although Staff argues that the cost of debt determination is for the purpose of calculating the return for this regulated reactive power operation, this operation is not a stand-alone one. It is part of Chehalis's overall operations, the primary purpose of which is to sell real power in the unregulated real power market. If Chehalis were to attempt to raise debt in the marketplace, it could only do so on the basis of its overall operations. It could not sell debt instruments based on the reactive power allocation. Clearly, Moody's Public Utility Index does not reflect the real risk of Chehalis's operations.

163. Chehalis's methodology for selecting proxies was not objectionable, but its execution was faulty, at least in part. Chehalis claims to have constructed a proxy group, utilizing publicly available information that would accurately gauge the cost of debt for IPPs doing business in the Pacific Northwest, which would reflect the cost at which Chehalis would be able to secure debt. Chehalis I.B. at 49-50. Accordingly, it deemed the other generators subject to the TransAlta Settlement to be appropriate proxies. *Id.* at 50. However, because the cost of debt of these entities was not publicly available at the time it filed its initial testimony, it selected what it deemed to be the next best alternative – the costs of debt of their parent corporations. *Id.* Calpine's average cost of long-term debt was 8.51%, and TransAlta's was 7.20%. Chehalis used the average of the two, 7.855%, as its proposed cost of debt. Ex. CPG-1 at 24.

164. Subsequently, prior to Chehalis' filing its rebuttal testimony, the cost of debt figures for the subsidiary-IPPs became available. The costs of debt for Calpine's subsidiary IPPs, Goldendale and Hermiston, were 9.34% and 10.81%, respectively. For TransAlta's subsidiary IPPs, Centralia and Big Hanaford, they were 6.75% and 6.70%, respectively. Ex. CPG-32 at 54. Chehalis claims that the midpoint of the range of these four subsidiary IPPs, 8.76%, compares favorably with the midpoint of the parents, 7.855%, which Chehalis claims as the proxy cost of debt. Chehalis I.B. at 51-52. Claiming the higher number, of course, would benefit Chehalis, but it did not seek a change.

165. Clearly, however, the parents' costs of debt were a poor substitute for the subsidiaries' and they did not fit the criteria laid out by Chehalis. In addition to independent power production, the Calpine parent is engaged in power marketing and gas gathering, and operates in the U.S., Canada and the U.K. Of Calpine's total of more than 26,000 megawatts of operating capacity, less than 1,000 megawatts are located in the Pacific Northwest. Tr. at 72-73. The TransAlta parent is a Canadian company that also engages in trading and marketing and owns facilities in Australia, Canada and Mexico. Ex. S-17 at 10-11. A majority of its generating facilities is located outside of the U.S. Tr. at 71-72.

166. In that the figures for the subsidiary IPPs became available before all the testimony was filed, and are now part of the record of the case, having been admitted as part of Chehalis' rebuttal testimony, there is no good reason for using the costs of debt of their parents, which are not comparable to Chehalis, in their stead.

167. Moreover, even more importantly, the Calpine entities, whether the parent or the two IPP subsidiaries that were part of the TransAlta settlement, are not comparable to Chehalis and cannot properly be used as proxies. At the end of the test year in this proceeding, 2004, unlike Chehalis, Calpine was a financially-troubled corporation on the verge of bankruptcy. It was given a credit rating of B by Standard and Poor's, considered a junk bond rating. Ex. BPA-11 at 34. It went on to file its bankruptcy on December 20, 2005. Tr. at 67-68. The wide disparity between the costs of debt of Calpine's subsidiary IPPs considered as proxies by Chehalis, 10.75%, and TransAlta's subsidiary IPPs considered as proxies, 6.725%, confirms Calpine and its subsidiaries' risky and unrepresentative financial standing that makes them unsuitable for inclusion in any proxy group. This leaves only the two TransAlta subsidiary-IPPs as suitable proxies.

168. While choosing a proxy group with only two entities to establish the cost of debt may not be preferred, there is no precedent for disqualifying that group solely on that basis. Moreover, the participants' failure to offer reasonable comparables other than those two entities leaves us with no other choice. Accordingly, I adopt 6.725%, the average cost of debt of those two qualifying IPPs, as Chehalis' cost of debt.

169. The reasonableness of this figure is confirmed by its closeness to the average yield of Moody's Baa-rated Public Utility Index, found by Staff's expert Douglas M. Green to be 6.36%. Ex. S-17 at 3. Moody's may appropriately be used to confirm reasonableness, even if not for the determination itself. And, it is to be expected that there would be much less of a difference between regulated companies and unregulated ones when it comes to debt, compared to equity, where the risks are small in any event, except for entities on the verge of bankruptcy. This is especially the case, now, where many of the investment costs of unregulated generation are passed on to transmission customers in the form of reactive power charges. The difference of 0.365% (6.725% - 6.36%) between the average debt of the TransAlta subsidiaries and Moody's Baa-rated Public Utility Index average confirms the reasonableness of the use of the TransAlta subsidiaries as proxies.

## IV. FINDINGS AND CONCLUSIONS

170. For reasons stated above, I make the following findings and conclusions:

1) Under the TransAlta Settlement, only the Service Factor may be updated annually.

2) Only the generator nameplate figures for power factor and power capability, and figures for real, reactive and apparent power consistent with them, may be used to calculate reactive power capability under the Current *AEP* Methodology under the Settlement Agreement.

3) Chehalis has failed to establish that it has the full reactive power capability it claims would qualify for inclusion in Schedule 2 under the Current *AEP* Methodology.

4) Chehalis has failed to show that its allocation of 38.7%, based on other than generator nameplate ratings, is proper under the Current *AEP* Methodology or is just or reasonable.

5) Under the Current *AEP* Methodology, Chehalis may allocate 27.75% of the costs of its power production plant and equipment to reactive power service.

6) The BPA 500 kV Switchyard is a transmission asset the costs of which are not includible in production plant or equipment or which may otherwise be allocated to reactive power service under the Current *AEP* Methodology.

7) The Chehalis Substation is a transmission asset the costs of which are not includible in production plant or equipment or which may otherwise be allocated to reactive power service under the Current *AEP* Methodology.

8) The Transmission Line Capacity Reservation Fee was paid entirely for real

power sales and none of it may be allocated to reactive power service.

9) Chehalis has failed to demonstrate that it incurred any of its claimed Natural Gas Interconnection and Metering Cost for construction and may not include any of the cost in Total Production Plant.

10) The $900,000 payment Chehalis made to BPA at closing was not shown to be a construction cost, rather than a return of monies paid for a commercial power purchase, and may not be included in Total Production Plant.

11) Chehalis has failed to demonstrate that it has incurred the costs of installation it claims so as include those costs in Total Production Plant and Accessory Electric Equipment. If it can break out the labor costs comparable to what was done by AEP, as described in the body of this Initial Decision, it may include those costs in those accounts, with the remainder of costs going to balance of plant. In the alternative, it may allocate costs using AEP as a proxy, as also described above. All the costs claimed by Chehalis that cannot be allocated to Total Production Plant and Accessory Electric Equipment pursuant to either alternative should go in balance of plant.

12) No heating losses were included by AEP in its reactive power methodology in *AEP*, *supra*, and none are includible by Chehalis in the Current *AEP* Methodology.

13) Chehalis has incurred only the equivalent of 49.982049 MWh in heating losses in producing reactive power during the test year, not the 11,106 MWh that it claims to be capable of incurring.

14) Chehalis lost no opportunity costs because of its heating losses.

15) The costs incurred in heating losses amounted to only $2,050 (49.982049 MWh x $41.02 in variable costs), not the $500,662.71 claimed by Chehalis.

16) None of the heating losses were incurred by Chehalis for transmission purposes and it would be unjust and unreasonable for it to pass any of those costs on to transmission customers.

17) Only the levelized method satisfies the Current *AEP* Methodology as adopted by the parties to the Settlement Agreement.

18) Only the levelized method is just and reasonable to calculate the reactive power service amount to be included in Schedule 2.

19) Of the proxies offered by the participants to establish Chehalis' cost of

debt, only the TransAlta subsidiaries were comparable to Chehalis. Their average cost of debt of 6.725% is a reasonable estimate of the amount of interest Chehalis would have to pay on its long-term debt in the marketplace.

Herbert Grossman
Presiding Administrative Law Judge